CONTINENTAL NATURAL GAS MARKET

CAPAC
IN THE 90s

Canadian
Energy
Research
Institute

Leonard A. Coad & David H. Maerz

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CONTINENTAL NATURAL GAS MARKET

CANADIAN EXPORT CAPACITY IN THE 90s

LEONARD A. COAD
DAVID H. MAERZ

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Continental Natural Gas Market
Canadian Export Capacity in the 90s

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Preface

The study authors wish to express their gratitude to the 21-member advisory committee for their valuable insights and comments on the analytical work presented herein. Their efforts have resulted in substantial improvements to this report. Thanks are also due to the staff of Decision Focus Inc. whose guidance in the use of the NARG model facilitated timely completion of the analytical work. Notwithstanding these valuable contributions, the study authors are responsible for any remaining errors or omissions.

Special thanks are due to a number of the Institute's staff. Janice Morrison and Beverly Kovacs prepared numerous drafts. Beverly Kovacs and Megan Murphy created the graphics and Vance Lickiss provided computer support. Nancy Sanford provided proofreading assistance. Zaytoon Janjua and Wendy Faid of the I. N. McKinnon Memorial Library gathered source materials. Dr. Gerry Angevine, Tony Reinsch and Merete Heggelund provided their support and guidance throughout the project.

EXECUTIVE SUMMARY

The central issue examined in this study is the level and timing of pipeline capacity additions that will best serve long-term requirements for natural gas trade between Canada and the U.S. A fundamental determinant in the analysis is the resource base believed to exist within the various supply regions in North America. The analysis has led to a number of interesting and significant outcomes with respect to the issues currently facing participants in the North American natural gas market. These outcomes are outlined below:

Findings Regarding the California Market

- Reference case results confirm that significantly increased pipeline capacity will be required to facilitate increased California demand growth.
- The availability of increased supplies will, not surprisingly, result in continued competition and prices that are lower than otherwise might be the case. Notwithstanding this, natural gas prices will likely rise steadily in real terms throughout the outlook period.
- Canadian natural gas exports to California show a consistent flow level across a wide range of scenarios examined.
- When transport cost and resource cost assumptions are combined, the North American Regional Gas (NARG) model indicates a requirement for the PGT/PG&E expansion as well as for the Kern River pipeline.
- Kern River provides an outlet for attractively priced Rocky Mountain supplies to both EOR and Southern California markets.
- Some Permian Basin and San Juan Basin supplies (up to 100 Bcf/yr) may be displaced by Rocky Mountain natural gas via Kern River.
- The PGT/PG&E expansion is well placed to meet market growth requirements in Northern California and to provide competitive supplies to Southern California as well.

- The viability of the Altamont line hinges critically on the relative resource costs and availabilities within the Alberta and U.S. Rocky Mountain supply regions. Alberta gas on the Altamont line may face significant competition from Wyoming producers for capacity in the Kern River pipeline.

Findings Regarding the U.S. Midwest Market

- Canadian exports to the East North Central region would be competitive with the export capacity expansions. It is even possible that Canadian gas could gain some market share in this area at the expense of U.S. supplies.

- Aggressive assumptions with respect to the Canadian conventional resource potential indicate a significant increase in Canadian exports to the U.S. Midwest (10 percent).

Findings Regarding the U.S. North East Market

- The conclusion reached with respect to the New England region is that exports of Canadian natural gas to this region may be supply constrained unless Canadian conventional resources are greater than expected.

- Conservative assumptions with respect to Appalachian region supply capabilities result in a significant increase in Canadian exports to New England.

Impacts of Alternative Resource Base Assumptions

- The greatest impacts upon Canadian natural gas exports among the scenarios examined involve those dealing with the Canadian resource base itself.

- Canadian exports toward the end of the outlook period (2000-2010) may be significantly constrained if Northern Canadian supplies from the Mackenzie Delta are not brought to market.

- Varying assumptions with regard to the conventional North American resource base could affect the timing of frontier supplies by as much as 5 years.

- Significant upside potential exists for B.C. natural gas supply over the outlook period.

- Saskatchewan production will continue to increase rapidly in the near term to meet expanding markets. Some questions arise with respect to long-term capabilities of the resource base.

- The impact of infill drilling on U.S. Lower-48 natural gas supply capability is potentially significant due to the relatively low cost of this resource.

- When conservative assumptions are made concerning the conventional resource base, consumer prices for natural gas rise significantly, reflecting increasing supply costs.

Conclusions

- Canadian natural gas exports exhibit considerably more variations across the scenarios examined than does Canadian domestic consumption. This result is obtained without imposing any form of surplus determination constraint. The implication is that Canadian consumers may be able to rely on market forces to ensure that their future requirements will be met.

- In order to sustain natural gas exports in the 1.9-2.0 Tcf/yr range, conventional resource discoveries must be in the high end of the current range of expectations and/or an orderly phase-in of Northern Canadian supplies must occur around the turn of the century.

- Increased export capacity will likely lead to increased market competition and prices that increase less rapidly through time than might otherwise be the case.

- The Iroquois project, which will serve principally the Mid-Atlantic market, is well supported by economic forces although some downside risk does exist.

- The combined capacity of Iroquois and Champlain to serve New England markets is perhaps too large. The market appears to require the full capacity of both projects only if the U.S. conventional resource base (particularly in the Appalachian region) is less abundant than currently anticipated.

Chapter 1

INTRODUCTION

The 1980s have been a decade of significant change for the North American natural gas industry. Much of the volatility has been associated with a transition from a heavily regulated industry to one characterized by decreasing government controls. The industry has also survived difficult economic conditions and acute supply/demand imbalances. This study examines some of the key issues relating to the North American natural gas industry as we enter the decade of the 1990s.

As the 1980s began, the natural gas industry faced government regulation at every turn. In Canada and in the United States, natural gas prices were fixed by governments. The U.S. had chosen to increase regulation of wellhead prices of natural gas destined for interstate commerce with the Natural Gas Policy Act of 1978 (NGPA). This action was in response to natural gas shortages that developed in the mid-1970s. The NGPA created multiple categories of natural gas production, each with a pricing formula. Natural gas supply contracts generally favoured the producer with "most favoured nation" clauses to guarantee favourable pricing, and take-or-pay clauses in the 80 to 95 percent range to ensure that the volumes actually shipped would be very close to the contract maximum.

In Canada, natural gas prices for interprovincial and international trade were set by federal-provincial agreement, and were rising rapidly in response to oil price trends. Canadian natural gas supply and deliverability were reaching all time highs, although after 1980 exploration activity decelerated in response to the National Energy Program. Natural gas trade between Canada and the U.S. was very robust as the 1970s ended.

Early in the 1980s, North American natural gas markets were beginning to show the strain of adjusting to volatile oil prices, economic downturns, pervasive regulation and surplus deliverability. Natural gas demand in the U.S. was falling and supply capability was growing. Shortage turned to surplus. The market put significant pressure on the rigid prices inspired by the Natural Gas Act, the NGPA and state level prorationing policies. As contract rates of take fell, pressure mounted to allow freer marketing of surplus natural gas supplies. Without the ability to adjust their prices, Canadian suppliers to U.S. markets saw their sales erode. The emphasis throughout North America had shifted from finding and developing low-cost natural gas supplies to finding and developing markets.

The mid-1980s saw governments in Canada and the U.S. begin to release their control over prices and marketing. Government/industry task forces on deregulation were instituted and protracted regulatory policy hearings became commonplace. As price controls were relaxed and finally lifted, producers in the U.S. and Canada were able to plan for a future based on market forces and adjustments, rather than legislation. Unfortunately, natural gas prices were permitted to find their level during a period of very low and volatile oil prices, making supply/demand balance even more elusive in many regional natural gas markets. Eventually, however, market forces began driving toward equilibrium rather than away from it.

As we prepare to enter the 1990s, there are many adjustments still to be made. In response to low prices and excess supply, drilling activity in both Canada and the U.S. has been severely depressed for the last 4 years. Some demand growth has been experienced as a result of lower prices. More importantly, supply and demand are coming into balance with contract terms beginning to reflect market forces rather than government regulations. Natural gas trade between Canada and the U.S. is once again reaching all time highs, and is expected to improve. Participants in all aspects of the industry are gaining experience with regulations aimed at promoting deregulation.

A key issue in North American natural gas markets for the 1990s will be control of access to pipelines. As the pipelines and distributors make critical strategic decisions concerning their roles as transporters and marketers, control over pipeline capacity may change hands. This evolutionary process will have far reaching impacts on natural gas marketing, as well as on new pipeline construction.

Significant capacity additions to existing pipelines and construction of new routes will occur over the next decade. These new facilities will permit development of new supplies and will be required to meet growing markets. They will occur, however, under significantly different circumstances than previously. Currently there is a definite preference for short-term contracts. The new expedited certificating procedures adopted by the Federal Energy Regulatory Commission (FERC) have placed greater risk on pipeline sponsors and shareholders. Increased participation by natural gas producers in transportation and marketing activities may be leading to their increased participation in pipeline construction and financing.

This study examines the major pipeline construction or expansion projects currently proposed for North America. It uses the same analytical framework as CERI Study No. 26, "Towards a Continental Natural Gas Market: Historical Perspectives and Long-Term Outlook." The model is described in that study and in an appendix to this study. The key issue examined in this study is the requirement for and timing of additional pipeline capacity to move Canadian natural gas to markets in Canada and the U.S. The study includes analysis of alternative pipeline routes and their implications for consumers and producers in various regions of North America.

Closely related to pipeline capacity additions, and of significant current interest, is the issue of resource base development. Long-term natural gas demands will be met in large part by natural gas resources that have not yet been developed and, in large part, not even discovered. The likely location, volume and cost of the undiscovered resource base will play a significant role in the final pipeline configurations.

Chapter 2 of this study provides an overview of industry developments and regulatory changes since the publication of Study No. 26, a summary of the supply/demand projections underlying the analysis and a description of the pipeline projects considered in this study. The analytical tool underlying this research is briefly described and a statement of the issues examined and scenarios considered is also included.

Chapter 3 provides key analytical results with respect to each major market to be reached by the pipeline projects. It also addresses conventional resource base development in regions of Canada and the U.S., as well as development of frontier reserves. Chapter 4 presents a synopsis of the study's key findings. Further details relating to the various pipeline projects, the analytical framework employed and input data are included as appendices.

Chapter 2

OVERVIEW OF RECENT DEVELOPMENTS AND INPUT ASSUMPTIONS

2.1 Regulatory Environment

In both Canada and the United States, progress continues toward the deregulation of natural gas markets. As progress is made, the natural gas market in North America approaches the ideal of a competitive market. To the extent that it is competitive, Canadian natural gas should thrive in an unrestricted market. This section highlights some of the recent developments leading toward deregulation in Canada and the U.S.

2.1.1 U.S. Developments

In the U.S. the focus remains on issues related to FERC Order 500, such as take-or-pay and open-access transportation, as understanding grows with respect to its interpretation and implementation. In this regard, virtually all of the major U.S. pipelines have moved toward acceptance of open access transportation with contract carriage rapidly becoming the standard method of natural gas transportation. Further, the issue of take-or-pay credits under Order 500, while far from being resolved, is beginning to be worked out. In general, progress is being made toward allocation or movement of natural gas within the United States being driven by market forces.

With regard to pipeline expansion, the optional certificate procedure, a streamlined approval process, has begun to be tested. Several of the pipeline expansion projects currently under consideration have been put forward under this procedure. The Wyoming-California Pipeline Company (WYCAL) has already received approval for its pipeline under the optional certificate procedure. An important implication of this approval procedure is the reallocation of risk, with the pipeline shareholders accepting relatively more risk than in the past. This is evidenced by rates that are negotiated between buyer and seller being based on published minimum and maximum tariffs. With project sponsors accepting less assurance of guaranteed return on investment the need for lengthy, protracted regulatory hearings has been reduced in the optional certificate procedure.

The issue of capacity brokering remains relatively less certain at this point. If implemented, however, capacity brokering is expected to dramatically affect the availability of capacity in certain markets, at certain times during the year. The availability of brokered capacity in an unfettered market should lead to a more efficient matching of transportation agreements with physical capacity. As the market determines the value of scarce capacity, an incentive will be created to make firm transportation capacity available to those who can use it. If the brokerage occurs at arms length in a competitive market, one might expect to see significant changes in companies' transportation strategies.

At this point, it appears that U.S. regulatory authorities will continue on a path toward further deregulation. Full price deregulation is scheduled for early in the next decade. However, lobby groups may seek restrictions upon the market to preserve their interests. The impact of the recently ratified Canada-U.S. Free Trade Agreement (FTA) in this regard is, as yet, uncertain. Generally, it is thought that the FTA will act to preserve the present situation of relatively unrestricted Canadian exports to the U.S., from the U.S. regulatory point of view.

2.1.2 Canadian Developments

Deregulation of the natural gas markets within Canada has also progressed. The relatively new National Energy Board (NEB) export approval procedure has been applied to several export applications and potential shippers are becoming more familiar with the new rules. The procedure lays down new ground rules for export approval based upon public interest, a demonstration of net benefits to Canada, and price and volume flexibility. A complaints mechanism has been included but has not been tested to date. Under the new export approval procedure, extensions to export permits and new export permits are granted on the basis of their impact upon Canadian public interest. Satisfying these criteria has led to a resurgence of cost-benefit analysis in an effort to quantify the net benefit to accrue to Canada as a result of a particular export of natural gas.

Within Canada, the ban on self-displacement has been lifted. Self-displacement is the procedure of converting distribution utility gas purchase contracts with the pipeline involved into direct consumer-producer transportation agreements. The distribution utility is then free to fill this transportation capacity with natural gas supply sources of its choice. Self-displacement greatly enhances the supply flexibility of distribution utilities. This action is a significant step toward resolution of the single most difficult issue in the deregulation of the Canadian natural gas industry. It has permitted a staged approach to increased competition in Canadian core markets for natural gas.

With the introduction of a minimum royalty price based on 80 percent of the average market price for the province, Alberta has permitted the market to find its own price level. At the same time, the Crown is protected from inappropriately low prices on individual sales of the Crown's share of production.

The above actions have propelled the Canadian natural gas industry into an era of increased competition. In some regions there remain contractual and institutional anomalies, although the general progression toward deregulation continues.

Deregulation of domestic natural gas markets and natural gas exports continues to progress. The Federal/Provincial monitoring committee established by the Agreement on Natural Gas Markets and Prices has more clearly defined its role. The committee is monitoring the movement away from markets restricted by regulation to a more competitive situation. This is also the larger objective of the Canada-U.S. Free Trade Agreement. The precise impact of the FTA on Canadian gas exports over the longer term is difficult to assess. However, it is generally expected to encourage greater involvement by U.S. corporations in the development of Canadian natural gas reserves to meet growing U.S. demand for Canadian natural gas.

2.2 North American Supply/Demand Projections

The source for the U.S. gas demand data used in this study is the "1988 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010," produced by the Gas Research Institute (GRI).[1] These projections have been inputted directly into the North American Regional Gas (NARG) model by U.S. census region and end-use sector. On average, natural gas consumption is projected to grow at a rate of 0.4 percent per year in the U.S. over the projection period. Underlying this relatively stable market outlook is a decline in gas use in the industrial and residential sectors and increased gas use in the electric utility and commercial sectors. The 1988 GRI Baseline Projection does not include an estimation of potential incremental demand for natural gas as a result of possible environmental regulations.

GRI's Baseline Projection is underlaid by a number of basic macroeconomic assumptions. Average real GNP growth in the United States is projected to be 2.3 percent per year over the period 1987 to 2010, with the percentage level of GNP growth declining over the projection period relative to earlier time periods. Consistent with this projected economic growth path, inflation (GNP Implicit Price Deflator) is projected to average 5.0 percent per year during the forecast period. More specifically, the average inflation rate is projected to be 4.4 percent per year between 1987 and 1995, and 5.3 percent per year between 1995 and 2010. The oil price path used in the 1988 Baseline Projection is given in Table 2.1.

TABLE 2.1

OIL PRICE ASSUMPTIONS
($1987 U.S.)

	GRI 1988 Baseline Projection[a]	NEB 1988 High Price[b]
1986 Actual		16.00
1987 Actual	17.91	
1988		20.00
1990		22.00
1995	23.25	27.00
2000	27.00	30.00
2005		30.00
2010	42.25	

SOURCES: Gas Research Institute, 1988 and National Energy Board, 1988.

[a] Projected U.S. average refiner acquisition cost of crude oil.
[b] West Texas Intermediate at Chicago.

As mentioned, U.S. residential gas consumption is projected to decline slightly over the period 1987 to 2010 (by about 2.2 percent). However, residential gas demand is projected to rise in the near term as the space heating share of new, single family homes increases. Following this rise in demand, although the number of gas-heating customers will continue to increase, efficiency improvements in new and replacement equipment (and increased thermal efficiency of homes) will more than offset the increase in the number of gas customers.

These increases in efficiency will not have the same impact across all regions in the U.S. In regions where a large percentage of the gas-fired heating systems are boilers and not furnaces, such as

New England and the Middle Atlantic, energy savings tend to be relatively less in boiler replacement as boiler efficiency improvements have been minimal. New appliance efficiency standards (to be enforced in 1992) may also affect the comparative economics of selecting space heating systems.

Gas consumption in the U.S. commercial sector is expected to increase by approximately 25 percent over the projection period. Whether or not this potential growth is achieved will depend upon the success of emerging gas-fired cooling and cogeneration technologies. The three emerging gas technologies which GRI has included in the projections are packaged cogeneration systems, heat pumps and double-effect, direct-fired absorption chillers. Without the contribution of these technologies it is felt that commercial gas consumption would remain relatively flat over the projection period.

In the industrial fuel and power consumption sector, gas demand is projected to increase until the mid-1990s, declining thereafter to slightly below 1987 levels by the year 2010. The two main components of this sector are boiler markets and process heat applications. A key factor in determining future levels of gas demand in this sector will be the ability of gas to compete with residual fuel oil and coal in the pricesensitive fuel and power markets. No new industrial technologies are included in this projection, other than cogeneration. The GRI 1988 Baseline Projection shows gas consumption by electric utilities to grow by approximately 14 percent between 1987 and 1995. From 1995 to the end of the projection period consumption is projected to increase by approximately 30 percent.

The source for the Canadian gas demand data is the NEB's 1988 assessment of Canadian energy supply and demand.[2] Data input into the NARG model were from the NEB's high oil price case which is based upon an assumption of world economic growth (apart from the centrally planned economies) averaging about 3 percent per year. The NEB projections for Canadian macroeconomic performance in its high case include real average annual growth in GDP of 2.9 percent over the projection period with inflation at 5.0 percent. The oil price track in the NEB high oil price case is given in Table 2.1.

The source of the U.S. supply data within the NARG model is the 1988 estimate of potential supply of natural gas in the United States by the Potential Gas Committee (PGC).[3] This estimate is of natural gas which can be recovered by conventional means given adequate economic incentives and using current or foreseeable technology. A number of categories of natural gas resources are used in the PGC estimation. In the reference case, most likely levels of future discoveries as estimated by the PGC were input to in the NARG model.

Potential supplies of natural gas as defined by the PGC include all of the undiscovered resource plus the portion of the discovered resource that is not included in proved reserves, that is, that portion of discovered resource that has not been confirmed by testing. Two other categories of potential supplies exist. The possible potential resources are those which exist outside of known fields, but that are associated with a productive formation in a productive province. Speculative resources are those resources which are expected to be found in formations or provinces which have not yet proven to be productive.

Key differences exist between the 1988 PGC estimates of the U.S. resource base and the 1986 estimates (used in prior versions of the NARG). Texas and Gulf Coast resources have been increased by 5.32 Tcf, East Texas resources have been increased by 1.92 Tcf, the Michigan Basin resource base has been increased by 4.27 Tcf, and various changes have been made to the Rocky Mountain resource base as well as the San Juan Basin. The 1988 PGC estimates of the U.S. resource base used in this study are presented in Section 2.4.

Canadian natural gas supply data used in this study were based on the 1988 NEB data and on discussions with the Geological Survey of Canada (GSC). Generally, a more optimistic outlook has been adopted with respect to the Canadian natural gas resource base than used in the version of the NARG model used by the CEC.

2.3 Summary of Pipeline Expansion Plans

Over the last 3 years, numerous pipeline configurations have been proposed to carry increased volumes of Canadian natural gas to various U.S. markets. California and the U.S. Northeast have been the focus of much of the attention. This study includes the 12 major projects described in Appendix A and summarized in Table 2.2. Projects not included are generally not sufficiently advanced to be modelled. The pipelines examined represent all major transmission corridors.

The sections which follow describe proposals to serve each market as well as to open up new supply regions. The objective is to provide a general overview of the corridors and competing proposals

TABLE 2.2

MAJOR PIPELINE PROJECTS
(to Oct. 2, 1989)

Project		Initial Capacity (MMcf/d)	Projected Maximum Tolls (100% Load Factor)
Alaska Natural Gas Transportation System		2300	$3.05/MMBtu ($U.S. 1988)
Altamont		700	$0.85/Mcf ($U.S. 1989)
Champlain		430	$0.90/Mcf ($U.S. 1991)
Iroquois		534	$0.70/Mcf ($U.S. 1991)
Kern River		700[a]	$0.53/Mcf ($U.S. 1989)
Mackenzie Valley Pipeline		1200	$1.60/Mcf ($U.S. 1988)
Mojave		400	$0.35/Mcf ($U.S. 1988)
Northern Border	(Phase I)	1350	$0.53 ($U.S. 1988)
	(Phase II)	1800	$0.39 ($U.S. 1988)
PGT Expansion		755	$0.73/Mcf[b] ($U.S. 1988)
WyCal		650	$0.81/Mcf ($U.S. 1987)

SOURCE: Canadian Energy Research Institute.

[a] To be expanded to 1.2 Bcf/d when Altamont is built.
[b] Does not include an estimated $0.05 (U.S.) on ANG.

examined. The reader is referred to Appendix A and to the proponents themselves for further details.

2.3.1 California

Many proposals and variants have been put forward for pipelines into California. Three major routes have been considered: a direct route from Alberta to California; a route from the Rocky Mountain region in the U.S. via Arizona and Nevada into California; and a route from Alberta to California via the Rocky Mountain route.

The key proponent of the Alberta to California direct route is the Pacific Gas Transmission Company (PGT). Its proposal involves capacity expansion by looping their existing transmission lines. This would make use of existing environmental approvals and rights of way. A projected investment of $945 million would permit the addition of 750 MMcf/d of capacity,[4] with 600 MMcf/d of increased deliveries to California. The project would also expand capacity on Pacific Gas and Electric's (PG&E) system and provide an interconnection with the Southern California Gas Company (SoCal). The tariff structure proposed would see no impact on PGT's existing shippers, but would recover the full cost of expansion from shippers using the incremental capacity. Most of the capacity on the new line would be controlled by the California distribution companies.

The Rocky Mountain to California route involves three proposals; Kern River Gas Transmission (Kern), Wyoming-California Pipeline Company (WyCal) and Mojave Pipeline Company (Mojave). Each of these pipelines has been under consideration for up to 4 years, with Kern and Mojave recently joining forces in an effort to combine markets and reduce transport costs. The Rocky Mountain region of the U.S. is relatively less explored than most other supply regions and has considerable potential. The proposed pipelines would serve the California enhanced oil recovery (EOR) market as originally planned, and would also make gas available to the utility market. The Kern River/Mojave joint venture would carry gas from Opal, Wyoming through Utah and Nevada, ending near Bakersfield, California. The Wycal proposal follows a similar route. The Kern River/Mojave line would be built to handle 700 MMcf/d of Rocky Mountain natural gas and the WyCal line to handle 650 MMcf/d. The two projects are essentially competing for access to the corridor as it is unlikely that sufficient incremental demand exists in California to fill both lines to capacity.

In addition to the PGT/PG&E expansion plan, a proposal has been put forward to build a line from Alberta to Wyoming, interconnecting with one of the Rocky Mountain to California lines. The most advanced proposal of this venture is the Altamont line from Alberta to Opal, Wyoming interconnecting with the Kern River Pipeline. Initially, Altamont gas would move through Northwest Pipeline into the Kern River line until a physical connection is made from Alberta to Wyoming. As it stood at the time of writing, the Altamont sponsors had reached agreement with Kern River for 200 MMcf/d of capacity. Facilities would need to be added to the Kern River line in order to accommodate the 700 MMcf/d of Altamont capacity originally envisioned. Total capacity on Kern River would eventually be approximately 1.1 Bcf/d. This proposal would compete directly with the PGT expansion for California markets and with Rocky Mountain gas supplies for space in the pipeline as well as markets.

2.3.2 The U.S. Midwest

Only one major expansion is planned for Canadian shipments into the U.S. Midwest. That project is the planned expansion of the East leg of the Alaska Natural Gas Transmission System (ANGTS) Canadian Prebuild section and the interconnected Northern Border Pipeline in the U.S. The initial stage of this expansion will be completed in 1990 and involves debottlenecking of interconnecting facilities between Foothills Pipe Lines Ltd. and NOVA (the Alberta natural gas gathering system). Additional expansions are anticipated to take the current capacity of 1.075 Bcf/d up to the system design capacity of 1.8 to 2.0 Bcf/d by additional compression. This expansion has been facilitated by a recent settlement of a long-standing dispute between Pan Alberta Gas Ltd., the major shipper on the line, and United Gas Pipeline Ltd.

In addition to the compression additions, an eventual extension of the Northern Border pipeline is envisioned. The current terminus at Ventura, Iowa would be the starting point of the extension to Tuscola, Illinois.

The expansion of the Foothills/Northern Border link would provide the benefit of a reduction in tolls for existing shippers. This is because pipeline construction is only required for the extension to Tuscola. The balance of the expansion requires relatively inexpensive compression additions.

2.3.3 The U.S. Northeast

Since the early 1980s, this region of the U.S. has received considerable attention from Canadian natural gas producers. It has been viewed as a potential growth market as natural gas displaces fuel oil both for end-use applications and for electricity generation. With the passage of Public Utilities Regulatory Policy Act (PURPA) legislation and the repeal of the Fuel Use Act to allow gas use for electric utility generation, natural gas use as a cogeneration fuel has become significantly more attractive.

Two major projects are currently planned to move additional volumes of Canadian natural gas into the U.S. Northeast. The Iroquois Gas Transmission System project (Iroquois) would carry up to 534 MMcf/d of Canadian gas from an interconnection with TransCanada Pipelines Limited (TCPL) to various markets in New York, Connecticut, Massachusetts, New Jersey, Rhode Island and New Hampshire. A total of 369 miles of pipeline would be laid (with no compression) at a total cost of $523.7 million (U.S.). The projected transmission tariff is $0.70/Mcf (U.S.). Recent producer approval votes have supported contracts for 397.1 MMcf/d of gas flow. An additional 25 MMcf/d of capacity has been awarded to Alberta Energy Company and Atcor Ltd.

An additional Champlain Pipeline Company proposal (Champlain) was originally slated to carry 430.6 MMcf/d of Canadian gas to markets in Vermont, New Hampshire, and Massachusetts (Boston area terminus). This line, costing $354.1 million (U.S.), would be completed in 1991/1992. There has been some difficulty obtaining producer approval for the system supply contracts envisioned for this line. Because of this, attention has shifted from aggregate supply pools to negotiations with individual producers. Failure to secure adequate supplies would likely result in a downsizing of the project.

The combined capacity of the Champlain and Iroquois pipelines would result in a large increment to Canadian export capacity to the U.S. Northeast. With a combined design capacity of over 350 Bcf/year, these lines are aimed at successful penetration of the existing market as well as significant future load growth.

Several smaller projects are also at various stages of planning or implementation. The Granite State pipeline project involved a reversal of an oil pipeline. The Empire State pipeline will provide a link between TCPL, Union Gas and a new pipeline from Niagara, Ontario to Syracuse, New York. This line would carry up to 150 MMcf/d of gas at a capital cost of $82.5 million, serving mainly a cogeneration market.

2.3.4 NOVA and TransCanada Pipelines

In order to accommodate the export pipeline projects described above, both the NOVA trunklines and the TCPL system will require additional capacity. For several years now it has been difficult to obtain firm capacity on NOVA's system to export natural gas from Alberta, with a 2-year lead time required for facilities construction. NOVA is currently completing $157 million in capacity additions to increase its receipt point capacity from 10.9 Bcf/d (in 1988) to 12.9 Bcf/d, effective November 1, 1989. A further expansion to 13.5 Bcf/d is planned for November 1, 1990. Delivery point capacity will be increased from 9.2 Bcf/d to 9.3, and then 10.1 Bcf/d. NOVA has also announced an intent to invest up to $3 billion by November 1, 1995 for further gathering system expansion. This would raise shipping costs to about $0.32/Mcf by 1995 and would accommodate all export projects currently planned except for Champlain and Iroquois. Additional facilities will be required for NOVA to accommodate these latter two projects.

The TCPL system is in a state of phased expansion to meet future domestic and export market requirements. Construction is currently underway to expand domestic capacity by 178 MMcf/d and export capacity by 278 MMcf/d as of November 1, 1989 at a cost of $567 million. Approval has been granted by the NEB for the next phase of expansion. This phase would add 78 MMcf/d of domestic capacity and 459 MMcf/d of export capacity at a cost of $652 million in Canada and $440 million (U.S.) in the United States on Great Lakes Gas Transmission's (GLGT) system. The final expansion currently envisioned has been applied for and is under active review. This phase would accommodate 499 MMcf/d of exports to Iroquois and 321 MMcf/d to Champlain. The total cost would be $1.2 billion in Canada and $970 million (U.S.) on GLGT. As the final requirements for Champlain and Iroquois become known, the required TCPL/GLGT expansion will also be finalized, and may be somewhat different than the figures quoted here. Total expenditures for TCPL expansion would exceed $2.4 billion with GLGT expansion adding in excess of $1.4 billion (U.S.). Such large-scale expansion is certain to reduce the recent downward trend in TCPL tolls, particularly as expansion costs are rolled into existing tolls.

2.3.5 Northern Canada and Alaska

Two projects have also been put forward as methods of moving frontier gas to market. The first involves a pipeline to tie in large natural gas reserves in the Mackenzie River Delta. This line would follow the Mackenzie River Valley southward into Alberta, eventually terminating at Caroline, Alberta where it would interconnect with the Foothills Prebuild System. The project would span 1400 miles at a cost of $4.4 billion. Shipping capacity would be 1.2 Bcf/d at a cost of approximately $1.60 U.S./Mcf. Three companies (Shell, Esso, and Gulf) have applied to the NEB for export permits totalling 9.2 Tcf that would make use of this line. Because of the potential role of this gas supply, the Mackenzie Valley line will be a key determinant of long-term Canadian natural gas export capability.

The northern portion of the Alaska Natural Gas Transmission System (ANGTS), originally proposed in the 1970s, has been recently revised. With more current construction cost estimates, reflecting lower interest rate assumptions, smaller diameter pipe and improved design, the projected capital cost has been reduced by 40 percent to $14.6 billion ($1988 U.S.). The line would carry up to 2.3 Bcf/d of gas from Alaska to the U.S., interconnecting with the Foothills system at Caroline. Unit shipping costs to the U.S. city gate are estimated to be $3.05/MMBtu ($1988 U.S.) on a 10-year levelized cost basis.

2.4 The Analytical Framework

The North American Regional Gas (NARG) model is an application of the Generalized Equilibrium Modeling System (GEMS). GEMS is a software package developed by Decision Focus Inc. (DFI) of Palo Alto, California to facilitate the construction of large-scale economic models which consist of systems of linked submodels. In the NARG model, process submodels are used to describe the activities of production, transmission and consumption of natural gas. The linked set of process models comprise a network which represents the spatial relationship between various demand and supply regions embodied in the transmission processes which interconnect them. In this context, the network does not refer to the transmission system itself but to a description of the interaction between the different processes including the transmission process. In addition, transmission processes do not necessarily model individual pipelines but, instead, model pipeline corridors between various supply and demand regions.

Generally, the process models consist of a set of mathematical relations that describe physical, behavioural and financial interactions. In the NARG, the generic GEMS process models are adapted to represent the specific model activities; resource supply, conversion (including transportation and distribution), allocation and end-use demand. The solution of the NARG model is an equilibrium set of prices and quantities through time for all the activities in the model. Here equilibrium implies a situation in which all the physical and behavioural process relations in all of the network's activities are simultaneously satisfied.

2.4.1 Modifications to the NARG Model

A number of modifications have been made to the NARG model since CERI Study No. 26. The following is a summary of the California Energy Commission's (CEC) efforts during 1987-1988 to expand and improve the NARG model:

- Disaggregated representation of Pacific census demand region into:

    - Pacific Northwest (Washington and Oregon);
    - Pacific Gas and Electric Company service region;
    - Southern California Gas service region;
    - San Diego Gas and Electric service region; and
    - Enhanced oil recovery region (Kern County).

- Disaggregated representation of natural gas supply regions serving California into:

    - San Juan region distinguished from the Permian basin; and
    - Onshore/offshore regions in Northern and Southern California.

- Western United States pipelines distinguished in more detail.

- Prospective new pipeline projects specifically represented.

Modification and enhancement have continued since the CEC effort. One example is the enhancement of the representation of British Columbia natural gas market activity. In the CEC NARG model and previous NARG models, British Columbia gas demand was treated as a single activity within the British Columbia supply sector. In the current version of the NARG model, British Columbia demand is modelled as a distinct sector at the same level of detail as all other demand sectors in the model, that is, a distinction between core and noncore is made with the potential for fuel switching in the noncore gas market.

A more recent change made by CERI for this study has been to separate the Middle Atlantic and New England census regions into two distinct demand sectors within the model. In prior versions of the model the these census regions were aggregated into a single demand region. The arguments for doing so were that pipeline alternatives were common, there is little indigenous supply in these regions and climatic differences are minor (relatively speaking). However, given the recent pipeline proposals to serve these regions from Canada, it is necessary to represent New England in a distinct manner in order to build a distinct export link from Canada to New England. Thus, the model used in this study has distinct export links from Canada to each of the Middle Atlantic and the New England regions.

With respect to the new pipeline proposals, expansion pipelines have been constrained to their designed capacity, unlike the CEC base case.

2.4.2 Reference Case Assumptions

At this point the key reference case assumptions are outlined. Previous sections have described in a more general sense the supply and demand projections underlying the analysis and the pipeline expansion plans. In the reference case, the pipeline expansions were modelled at their stated capacity.

In Table 2.3, reference service demands and corresponding prices used in the reference case, and all impact scenarios, are given (the sources of which have been discussed in Section 2.2). In an inelastic demand case, such as the recent CEC base case,[5] these reference service demands dictate demand in each period of the model. This study, however, has employed the elastic demand option available in the NARG model to allow for a price response in gas demand. Price elasticities input for U.S. and Canadian gas demands were assumed to be constant across consuming regions and to represent the response of total gas demand within a region to a change in price. Elasticities used were generally 0.10 as a short-run elasticity and 0.60 as a long-run elasticity. Thus, the model has the ability to move away from the quantity-price pairs given in Table 2.3.

TABLE 2.3

REFERENCE CASE - REFERENCE DEMAND AND PRICE PAIRS BY REGION

	1987				1992				1997			
	Demand (Tcf)		Price ($)		Demand (Tcf)		Price ($)		Demand (Tcf)		Price ($)	
	core	noncore	core	noncore	core	noncore	core	noncore	core	noncore	core	noncore
South Alaska	0.19		1.12		0.21		1.15		0.21		1.18	
Pacific N.W.	0.14	0.09	2.04	2.26	0.09	0.23	2.47	2.68	0.12	0.22	3.04	3.25
WNC/Mountain	1.60	0.45	3.50	2.78	1.61	0.38	4.01	3.25	1.61	0.37	4.81	4.02
West South Central	2.70	2.88	2.41	2.36	2.53	2.90	2.96	2.86	2.58	2.88	3.66	3.55
East North Central	2.56	0.59	3.78	2.82	2.50	0.59	4.38	3.37	2.43	0.59	5.12	4.08
East South Central	0.49	0.28	3.25	2.63	0.54	0.28	3.85	3.16	0.55	0.28	4.55	3.85
S. Atlantic	0.82	0.82	4.34	2.95	0.94	1.03	4.99	3.48	0.98	1.15	5.66	4.14
Mid-Atlantic	1.31	1.00	5.46	3.08	1.31	1.00	6.11	3.55	1.32	1.00	6.87	4.23
Socal Gas Co.	0.43	0.44	5.33	2.67	0.52	0.43	6.05	3.36	0.54	0.53	6.82	4.12
PG&E Co.	0.33	0.46	4.92	2.82	0.40	0.45	5.49	3.35	0.41	0.56	6.25	4.10
SDG&E Co.	0.05	0.07	4.76	2.82	0.06	0.07	5.46	3.48	0.06	0.09	6.21	4.23
EOR Calif.	0.20		2.59		0.19		3.30		0.24		3.97	
New England	0.31	0.28	6.14	3.34	0.32	0.28	6.76	3.96	0.33	0.29	7.53	4.73
Western Canada	0.70	0.01	2.59	1.84	0.79	0.02	3.11	2.36	0.83	0.02	3.68	2.93
Eastern Canada	0.14	0.05	4.01	3.21	0.20	0.06	4.42	3.63	0.23	0.09	5.09	4.30
Ontario	0.57	0.15	3.65	2.60	0.62	0.18	4.05	3.00	0.68	0.20	4.70	3.65
British Columbia	0.19	0.00	2.43	1.68	0.22	0.01	2.80	2.05	0.25	0.01	3.27	2.52

Continued on Next Page

TABLE 2.3 (Continued)

	2002				2007				2012			
	Demand (Tcf)		Price ($)		Demand (Tcf)		Price ($)		Demand (Tcf)		Price ($)	
	core	noncore	core	noncore	core	noncore	core	noncore	core	noncore	core	noncore
South Alaska	0.22		1.25		0.23		1.34		0.24		1.45	
Pacific N.W.	0.12	0.19	3.73	3.94	0.15	0.19	4.62	4.83	0.20	0.19	5.71	5.94
WNC/Mountain	1.62	0.38	5.60	4.84	1.62	0.41	6.45	5.75	1.63	0.41	7.07	6.41
West South Central	2.45	3.00	4.46	4.36	2.30	3.08	5.34	5.25	2.24	3.10	6.41	6.32
East North Central	2.36	0.65	5.93	4.93	2.30	0.72	6.85	5.91	2.27	0.73	7.96	7.01
East South Central	0.56	0.39	5.33	4.65	0.57	0.47	6.22	5.56	0.58	0.48	7.32	6.66
S. Atlantic	1.02	1.14	6.40	4.94	1.07	1.16	7.32	5.93	1.10	1.15	8.53	7.10
Mid-Atlantic	1.33	1.00	7.68	5.11	1.34	1.00	8.65	6.20	1.35	1.00	9.86	7.35
Socal Gas Co.	0.55	0.63	7.65	4.95	0.56	0.68	8.52	5.81	0.56	0.70	9.56	6.82
PG&E Co.	0.42	0.66	6.99	4.85	0.42	0.72	7.81	5.67	0.43	0.74	8.96	6.78
SDG&E Co.	0.06	0.10	7.02	5.07	0.06	0.11	7.86	5.94	0.06	0.11	8.87	6.95
EOR Calif.	0.28		4.80		0.31		5.79		0.32		6.87	
New England	0.34	0.30	8.46	5.66	0.35	0.30	9.41	6.61	0.36	0.31	10.64	7.84
Western Canada	0.90	0.02	4.33	3.58	0.99	0.02	5.08	4.33	1.08	0.02	6.16	5.42
Eastern Canada	0.24	0.09	5.88	5.11	0.24	0.09	6.84	6.09	0.25	0.09	8.11	7.34
Ontario	0.72	0.22	5.47	4.42	0.85	0.23	6.39	5.36	0.89	0.25	7.63	6.63
British Columbia	0.27	0.01	3.81	3.06	0.29	0.01	4.55	3.80	0.31	0.01	5.76	5.01

SOURCE: Canadian Energy Research Institute.

As discussed in Section 2.2, the supply data in the model have been modified from previous versions of the NARG model for this study. The levels of established reserves and future reserves additions assumed for the reference case are provided in Table 2.4. These data correspond to PGC estimates of most probable resources for each supply region. It is noted here that the various supply sources are grouped according to the supply regions in the model. Supply sources referred to elsewhere in the study but not depicted in Table 2.4 have been turned off in the reference case.

2.5 Issues and Scenarios

The central issue examined by this study is the level and timing of pipeline capacity additions that will best serve long-term requirements for natural gas trade between Canada and the U.S. This issue must be examined from several points of view.

To Canadian natural gas producers, new pipelines mean potential new access routes to existing markets, together with greater growth potential. It may also mean risk of lower netbacks due to higher transport costs on undepreciated new facilities. Such a situation would be rendered critical by lower than expected levels of shipments on new pipelines, or by increased competition in the marketplace. The Canadian producer will be looking at the long-term potential for increased sales and attractive, stable prices offered by the various expansion projects.

The U.S. producer will view increased pipeline capacity from a different position. Much of the capacity will bring increased competition from potentially lower-cost Canadian sources. With increased competition comes the threat of price instability and lost markets. The focus then turns to developing alternative U.S. supplies and ensuring continuing competitiveness and market retention. In the case of certain regions such as the Rocky Mountains, producers will view pipeline projects as an opportunity to increase supply capabilities and penetrate new markets.

To U.S. consumers, pipeline expansions will bring diversity of supply. Canadian gas will be capable of providing alternative supply for a greater volume of U.S. requirements. Increased competition could also provide the benefit of lower prices, at least in the short run.

TABLE 2.4

REFERENCE CASE - NATURAL GAS SUPPLY ASSUMPTIONS BY REGION
(Tcf)

Supply	Remaining Established Reserves (1988)	Cumulative Reserve Additions
North Alaska	10.00	98.40
South Alaska	2.82	20.40
San Juan	4.91	9.99
Rocky Mountains (Shallow)	6.42	73.90
Rocky Mountains (Deep)	1.00	39.40
Northern Great Plains (Shallow)	0.51	15.50
Northern Great Plains (Deep)	10.00	2.40
Anadarko (Shallow)	19.34	62.50
Anadarko (Deep)	10.40	24.50
Permian (Shallow)	12.43	33.00
Permian (Deep)	0.88	21.20
North Central	3.21	18.90
Appalachian (Shallow)	4.36	48.10
Appalachian (Deep)	10.00	12.30
Atlantic Offshore	10.00	13.20
Onshore Lousiana	12.25	4.90
Onshore S. Texas	18.53	16.00
Arkoma Onshore	13.52	11.40
S.E. Gulf Onshore	2.50	4.00
Gulf of Mexico Onshore (Deep)	10.00	43.30
Gulf of Mexico Offshore (Shallow)	46.40	70.50
Gulf of Mexico Offshore (Deep)	10.00	60.70
S. California (Onshore)	2.28	4.30
S. California (Offshore)	0.30	5.80
N. California (Onshore)	1.54	6.00
Pacific N.W.	0.26	4.00
British Columbia	7.50	21.00
Alberta	52.50	70.00
Saskatchewan	5.10	4.00
Northern Canada (Onshore)	15.00	80.00
Northern Canada (Offshore)	15.00	15.00
Eastern Canada	1.50	8.20

SOURCE: Canadian Energy Research Institute.

Canadian consumers will no doubt view the question of optimal pipeline capacity from a different perspective. Canadian consumers in Ontario and Quebec have no indigenous gas supply and very limited import capacity from the U.S. They are critically dependent on Western Canadian supplies. The pipeline expansion projects have a variety of possible impacts on Canadian consumers, and are difficult to analyze. Increased exports will bring more rapid depletion of low-cost conventional resources and a more rapid transition to higher cost supplies, perhaps from frontier regions. Pipeline tariffs may also be higher with expanded capacity. On the positive side, Canadian consumers should feel the impact of lower prices in the U.S., if increased exports lead to increased competition resulting in lower wellhead prices. The future level of exports may also play a key role in achieving the critical level of flow required to exploit frontier resources.

Whichever viewpoint is taken, a key determinant of the analysis is the resource base believed to exist in North America. Much of the pipeline capacity to be added over the next decade will be filled (or not filled) for many years to come by as yet undiscovered natural gas. An analysis of a wide range of regional resource availabilities and of resources of different qualities forms a key element of this study.

Scenarios have been developed to aid in examining the key issues outlined above. With respect to pipeline capacity, several interesting permutations arise. Scenarios were developed to examine competing proposals for individual pipeline corridors, as well as to compare corridors. The Altamont/Kern River/Mojave projects are compared to expansion of Pacific Gas Transmission (PGT) as a means of serving the California market. Scenarios were also developed to consider the relative impacts of serving California vs. the U.S. Northeast. Consideration was given to a variety of minor projects aimed at removing bottlenecks in the existing U.S. pipeline grid.

Specifically, four pipeline scenarios were run in addition to the reference case. The No New Pipelines scenario limits pipeline capacity on existing export lines to current levels and does not permit new pipelines to be built. Some caution is required in comparing this case to other cases run in that the NARG model imposes capacity restrictions by means of cost penalties. As flow on a given corridor approaches and attempts to exceed the maximum level specified, the model imposes a penalty on operating costs. As the flow moves farther above capacity, the penalty increases until additional flows become uneconomic. In some cases, the model will flow as much as 10 to 15 percent above capacity. This flow may be considered to represent additional compression or minor looping and debottlenecking.

The No PGT Loop scenario follows reference case assumptions except that the PGT/PG&E expansion is not allowed to be put in place. The No New California scenario turns off all new capacity between Canada and California. The No Champlain/Iroquois scenario turns off the Champlain line and that portion of Iroquois dedicated to the New England market. All other input assumptions follow the reference case.

In interpreting the results presented below with respect to the pipeline scenarios developed, several factors must be considered. The NARG model is a long-term planning model that represents pipeline corridors rather than specific pipelines. As such, it abstracts from reality in several regards. All pipeline tariffs used in the model are expressed in constant 1987 U.S. dollars, with no change through time. Pipeline tolls are also invariant to load factor and represent a blend of rates on the various pipelines comprising a given corridor. No consideration is given to underutilization of pipeline capacity due to contractual constraints. In interpreting the results of the NARG model, the reader must be aware of such factors, particularly where the various pipeline configurations are at issue.

With respect to frontier regions, pipelines were modelled to move Alaska, Mackenzie Valley, Arctic Island and Sable Island gas to the relevant markets. Such projects are, of course, critically dependent on transportation costs, the available resource base, and an ability to achieve a minimum critical flow to trigger development.

On the resource base side, all scenarios use the estimates of the Potential Gas Committee as a starting point for the U.S. For Canada, estimates are based on NEB projections, supplemented by provincial data and by the Geological Survey of Canada, and by CERI estimates.

The Potential Gas Committee provides minimum, most-likely, and maximum volumes likely to be discovered in each of three categories: probable, possible and speculative. Probable resources include future extensions to existing pools, as well as new pool discoveries in existing fields in formations known to be productive in that geological province. Probable resources are the most certain PGC category. Possible resources include new discoveries outside of existing fields, but still within formations known to be productive in that geological province. Speculative resources are those believed to exist in formations or provinces not currently known to be productive.

As mentioned, the reference case developed for this study is based on 1988 PGC estimates of most probable resources in each category, together with the cost estimates developed by Geological Exploration Associates. Resource base scenarios were developed by reducing PGC estimates to minimum levels or increasing them to maximum levels as appropriate. The scenarios are designed to capture a range of possible impacts for conventional resource discoveries, infill drilling, coalbed methane, tight gas, frontier resources, Rocky Mountain region supplies and Gulf Coast supplies. In all cases, adjustments to available quantities are made to all cost categories proportionately. No incremental resource cost analysis was undertaken for this study.

For the conventional resource base, two scenarios were developed. The first reduces speculative reserves to the minimum level estimated by the PGC, leaving both probable and possible estimates at their most-likely level. This represents a conservative view of the undiscovered, potential conventional resource. An optimistic view is represented by a scenario that takes probable and possible categories to the maximum estimates, leaving speculative at its most-likely level. These scenarios test the impact of varying estimates of future conventional discoveries on the optimal pipeline configuration.

Two scenarios examine the potential impact of infill drilling in conventional, onshore areas. The first adds a total of 60 Tcf available at prices below $3.00/Mcf at the wellhead. The second, more optimistic view includes 180 Tcf of additional reserves, with 85 Tcf available below $3.00/Mcf. The relative magnitudes of these two scenarios reflect considerable uncertainty regarding the potential impact of infill drilling.

The future contribution of the offshore Gulf Coast is also the subject of uncertainty. A conservative scenario reduces possible and speculative resources to minimum levels, and an optimistic scenario raises probable and possible categories to maximum estimates. Significant technological improvements may be required to facilitate economic exploitation of much of the offshore resource, particularly in deeper water.

The Rocky Mountain area has received significant attention in its bid to supply future natural gas requirements in California. Successful long-term development of this region's supply capability

TABLE 2.5

RESOURCE BASE ASSUMPTIONS - FUTURE POTENTIAL (Tcf)

	Lower-48	Total U.S.	Western Canada	Total Canada
Reference Case	605.8	724.6	95	198.2
Conservative Conventional	452.0	506.4	95	198.2
Moderate Infill Drilling	666.0	784.8	95	198.2
Aggressive Infill Drilling	785.8	904.6	95	198.2
Conservative Offshore Gulf Coast	513.1	631.9	95	198.2
Aggressive Offshore Gulf Coast	680.3	799.1	95	198.2
Conservative Coalbed Methane	645.8	764.6	95	198.2
Aggressive Coalbed Methane	702.8	821.6	95	198.2
Conservative Rocky Mountain	561.7	680.5	95	198.2
Aggressive Rocky Mountain	638.4	757.2	95	198.2
Tight Gas	781.8	900.6	135	238.2
Aggressive North American Conventional	863.4	1057.7	155	277.2
Aggressive Canadian Conventional	605.8	724.6	155	258.2
No Canadian Frontier	605.8	724.6	95	95
Aggressive Canadian Frontier	605.8	724.6	95	218.2

SOURCE: Canadian Energy Research Institute.

NOTE: All resource base scenario cases include the reference case pipeline configuration, i.e., all new projects are available.

will depend on the development of sufficiently large pools to expand infrastructure economically. Two scenarios were developed, one reducing possible and speculative resources to minimum levels, the other increasing probable and possible categories to maximum estimates.

The impact of low permeability reservoirs has long been a subject of debate. Fracturing technology has improved and costs have been reduced, but this is still a risky, expensive source of natural gas reserves. A scenario was run which makes available 40 Tcf of low permeability gas in Alberta and 150 Tcf in the U.S.

The final set of resource base scenarios examines the Canadian resource potential independent of changes to the U.S. resource base. Conventional potential is increased to 35 Tcf for British Columbia, 110 Tcf for Alberta and 10 Tcf for Saskatchewan in the Aggressive Canadian Conventional case. Frontier resources are increased by 20 percent in the Aggressive Canadian Frontier scenario.

The undiscovered potential resource base assumed in the reference case and each impact is outlined in Table 2.5. For each of the resource base impacts, all other input assumptions are taken from the reference case. Specifically, the pipeline configuration includes all relevant expansions, except for the No Canadian Frontier case, where the Mackenzie Valley and Sable Island pipelines are not made available.

The pipeline scenarios outlined above were all run against reference case supplies and are intended to compare pipeline configurations under a static set of resource base assumptions. The resource scenarios were all run against the reference case pipeline configuration. It is important to note that although expansion projects and new pipelines are available to the model, the decision to build any project is not fixed. The NARG model will, in each resource scenario, choose that pipeline configuration that is most appropriate.

As stated above, the purpose of this study's scenario analysis is to gain greater understanding of the risks and impacts of the various pipeline expansion projects. Detailed analytical results are presented in Chapter 3.

Footnotes

[1] Gas Research Institute, 1988 Baseline Projection of U.S. Energy Supply and Demand to 2010, Gas Research Insights (Chicago, Illinois: GRI, December 1988).

The as yet unpublished 1989 GRI Baseline Projection of U.S. Energy Supply and Demand is expected to differ from the projection used in this study, in that the 1989 projection will likely be based upon a generally lower oil price track. This implies generally lower energy prices and relatively higher levels of gas demand.

[2] National Energy Board, Canadian Energy Supply and Demand 1987-2005 (Ottawa, Ontario: Minister of Supply and Services Canada, September 1988).

[3] Potential Gas Committee, Potential Supply of Natural Gas in the United States (Golden, Colorado: Potential Gas Agency, Colorado School of Mines, December 1988).

[4] Recently, September 1989, PGT has announced a capacity of 915 MMcf/d (765 to California and 150 to the Pacific N.W). This has not been modelled in this study.

[5] California Energy Commission, An Economic Evaluation of Alternative Interstate Pipeline Projects to Serve California (Sacramento, California: California Energy Commission, March 1989).

Chapter 3

ANALYTICAL RESULTS

This chapter outlines the key findings of this study. The following chapter summarizes the conclusions that can be drawn from those findings. Before proceeding some discussion of the analytical framework is in order.

The NARG model used for this analysis is a combination of process modelling, networking, partial equilibrium analysis and Hotelling-style depletable resource theory. The NARG is well grounded in economic theory. The underpinnings of the model have been discussed elsewhere and are not presented here. However, a few observations are provided.

The NARG model incorporates a representation of economic behaviour based on rational expectations. In its simplest representation, this means that decisions are based on perfect knowledge of relevant events in the past, present and future. Any errors in expectations are assumed to be random, and hence irrelevant in terms of specifying behavioural relationships.

The framework used by the NARG model considers supply options in considerable detail. Based on full knowledge of financial and economic parameters, optimal supply patterns are developed for each supply process in the model. These supply processes are tied to relevant allocation points by means of a transportation network. The network embodies its own financial, economic and operating parameters.

Within a given allocation process, requirements are met by least-cost available supplies. Certain constraints are imposed to prevent corner solutions and to represent non-price factors.

The demand processes in the NARG are simple price-quantity pairs for each process in the network in each time period. Should prices deviate from the reference levels, quantities are adjusted by means of short-run and long-run elasticities.

The NARG model considers all available supplies for a given location, and attempts to find a set of prices for each time period that brings about a balance between supply and demand. These equilibrium values for prices and quantities represent an extremely complex interaction.

The methodology incorporated in the NARG model is generally based on assumptions of perfect foresight and competitive market behaviour. Deviations from such behaviour are captured by means of constraints. As with any such model, the NARG model represents an imperfect representation of the real world. In examining the results generated by the NARG model, it is important to remember that they represent an approximation of reality, colored by the insights and expectations of the analyst. The results should thus be considered most valuable for the directional information they provide. This is particularly important in dealing with a clairvoyant model based on perfect foresight. Such models often indicate what ought to be, as opposed to what might be.

The following three sections provide a brief background and key results for each of the three regions targeted by the pipeline expansion projects. The key results with respect to U.S. and Canadian resource base development are then presented. Finally, some observations are provided with respect to the regional impacts of the various projects. Detailed scenario results are provided in tabular form in Appendix B.

3.1 California

Since completion of the Pacific Gas Transmission Ltd. (PGT) main line from Kingsgate, B.C. to Malin, Ore. (on the California border), California has been a key market for Canadian natural gas exports. Completion of the west leg of the Alaska Natural Gas Transmission System prebuild section provided access to Southern California markets.

Natural gas requirements in California currently exceed 5 Bcf/d (1.88 Tcf/yr). Although some recent slackening of demand in the electric utility sector has occurred, a long-term growth trend is anticipated. This will be due to a number of factors, including overall population and economic growth in California that is projected to continue to exceed national U.S. averages.

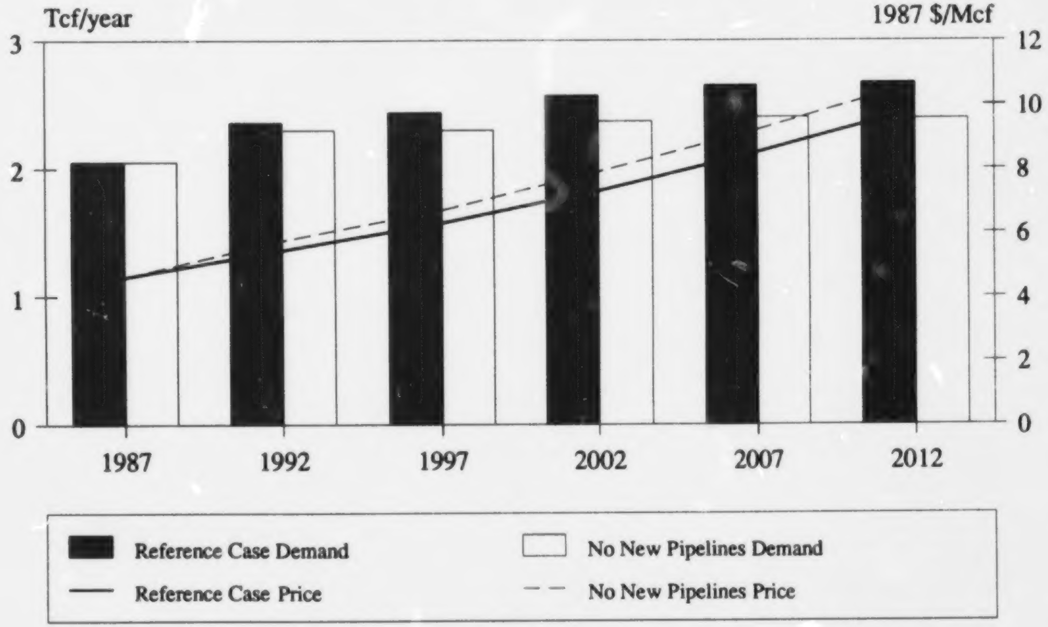
Residential and commercial markets for natural gas are expected to exhibit steady growth in response to population growth. Commercial and industrial cogeneration are expected to provide growth opportunities for natural gas sales. The enhanced oil recovery market is also expected to be a key growth area, with natural gas demand for fuel and EOR cogeneration doubling its 1987 level by 1990, then continuing to grow at a steady, although more moderate rate. Electric utility demand is expected to show a steady increase after reductions to more normal levels for 1988 and 1989.

The various pipeline projects for California have three key objectives: provide for market expansion, improve the infrastructure within the state, and offer better diversity of supply. Not all proposals contribute to each goal, although as a group they do. The PGT/PG&E loop and expansion will provide increased capacity to satisfy new markets as well as improved interties between PG&E and SoCal Gas for movement of gas within California. The WyCal and Kern River/Mojave proposals provide increased capacity as well as expanded access to future supplies in the Rocky Mountain region of the U.S. and, for Mojave, possibly coal seam gas.

Our reference case results indicate that increased pipeline capacity to California will be required to facilitate demand growth. The availability of increased supplies will, not surprisingly, result in continued competition and prices that are lower than otherwise might be the case. Figure 3.1 illustrates average burner-tip price and demand trends under the reference case with all expansion projects available as compared to a case which restricts flows to existing pipeline capacities. Although prices do increase steadily under reference case assumptions, they remain significantly lower than under the restricted case. This is a common theme throughout the analysis of regions and scenarios.

Under the reference case assumptions, natural gas exports to California are significantly increased over the restricted case levels (see Figure 3.2). The difference is consistently 160 Bcf/yr. However, this is somewhat understated as in the restricted case export flows to California via the PGT main line exceed existing capacity in spite of the stiff penalty imposed by the model. The NARG model is thus suggesting that even with a stiff transportation cost penalty increased volumes of Canadian gas would move into California. This should not be interpreted as an absolute preference over the Rocky Mountain to California route as that corridor is not available in the restricted case. However, it does indicate the significant value of Canadian natural gas supplies to California consumers.

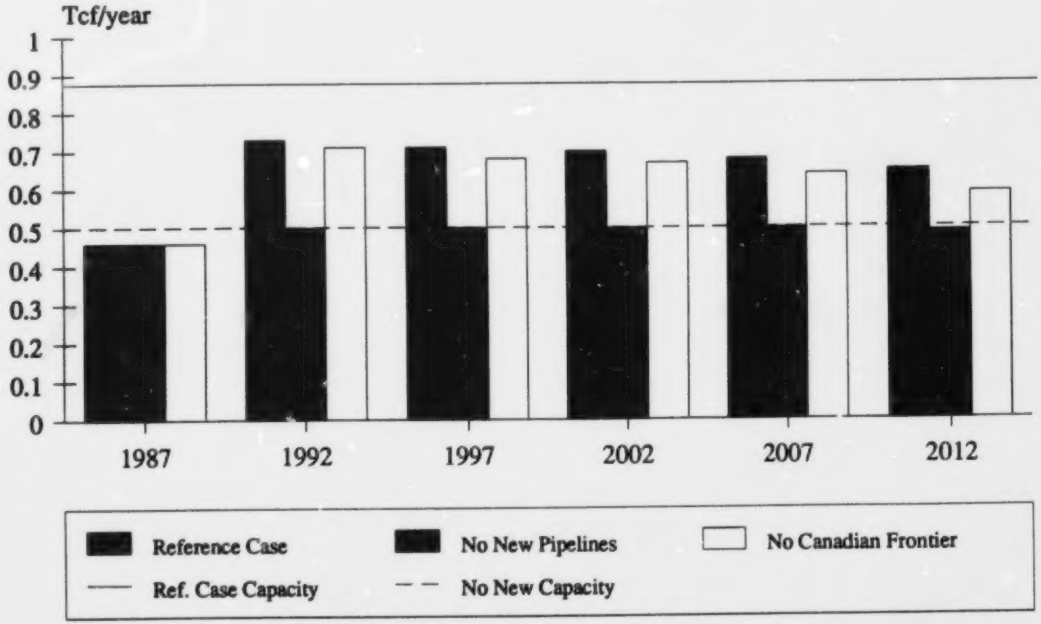
Figure 3.1
Comparison of California Burner-Tip
Natural Gas Prices and Demands



Sources: Table B.9 and B.29.

Figure 3.2

Natural Gas Exports to California and Export Capacity



Source: Table B.24.

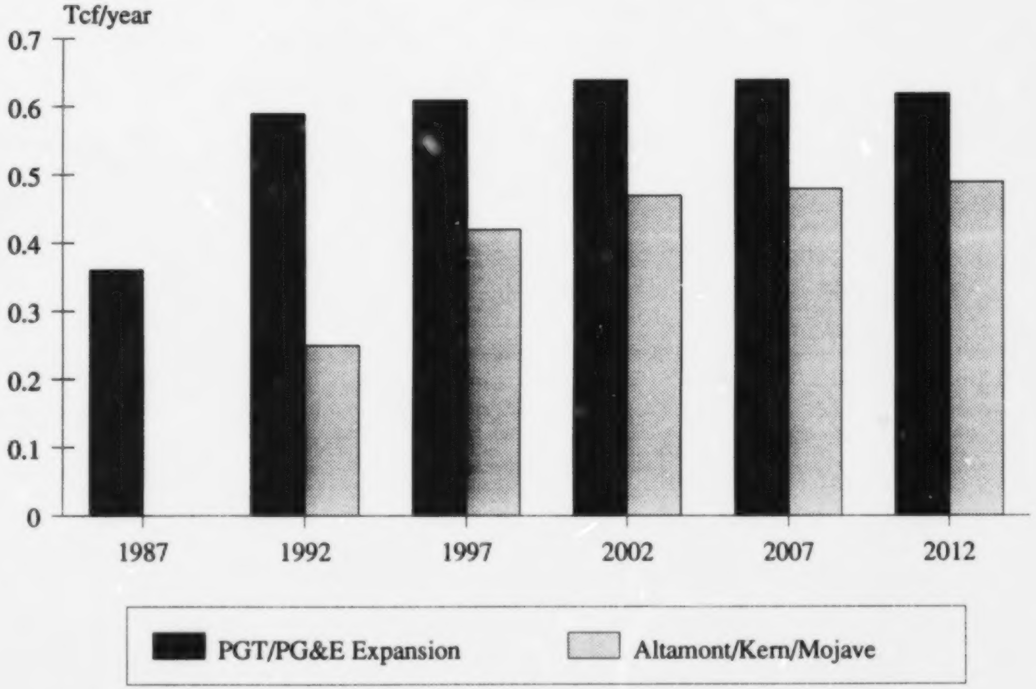
Another interesting result of the analysis is that Canadian natural gas exports show remarkably consistent flow levels across virtually all scenarios examined. This clearly indicates that Canadian gas can be competitive with U.S. supplies to California under a wide range of assumptions regarding resource availabilities. Varying levels of infill drilling, availabilities of offshore Gulf Coast supplies, coalbed methane, tight gas, and conventional reserves have virtually no impact. Even aggressive assumptions with respect to Rocky Mountain region supplies have little impact.

This positive result for Canadian exporters must be qualified in two directions. First, although the individual circumstances modelled provide no insurmountable barriers, their many possible combined effects were not examined. Many other permutations could be considered. Second, the NARG model, in the cases examined, assumes an ability to be competitive, free of regulatory barriers in both countries.

The one condition other than available pipeline capacity that has a significant effect on exports to California is the availability of Canadian frontier resources. As depicted in Figure 3.2, when natural gas from the Mackenzie Valley is prevented from flowing, exports to California are restricted by almost 10 percent by the end of the forecast horizon. This reflects the importance of a future transition to frontier supplies. Without them, competitively priced Canadian gas may not be available in sufficient quantities to take full advantage of pipeline capacity. This theme is explored more fully in Section 3.5. Note that in Figure 3.2, when frontier gas is not available, flows to California are restricted in all time periods. This is likely a result of the model's clairvoyant decision-making processes. *In reality one would expect the adjustment to come later in the period (when it is discovered that expectations of frontier capabilities had not been met) and to be more abrupt.*

A final area of interest with respect to California is the competition between the PGT expansion and the Altamont/Kern River/Mojave corridor. Figure 3.3 compares natural gas flows projected for the reference case via a combined PGT/PG&E expansion vs. the Altamont/Kern River/Mojave combination. On the basis of economic parameters, the NARG model chooses to increase both the PGT and Kern River expansions to their full capacities as soon as they are available. It is noted that, with the exception of Kern River, final binding arrangements are not in place.

Figure 3.3
California Pipeline Expansion Comparison



Source: CERI.

This result must be interpreted in the light of certain key model assumptions and decision rules. The PGT vs. Kern River competition, as represented in the NARG model, involves five pipeline corridors and four resource supply regions. The supply regions include Alberta, U.S. Rocky Mountain, San Juan Basin and Permian Basin. Alberta natural gas flows to Northern California via PGT, to Southern California via the PGT/PG&E expansion and to the Rocky Mountain supply region via the Altamont line. A mixture of Rocky Mountain and Alberta supplies can then flow directly to EOR markets and on to Southern California via Kern River.

Supplies from the San Juan basin flow to EOR markets via Mojave, and to Northern and Southern California markets via El Paso. Finally, Permian Basin supplies flow to Southern California markets via El Paso and Transwestern.

Two factors must be examined in interpreting the flow patterns indicated by the NARG model: relative transportation costs and relative resource costs. The results regarding PGT/PG&E expansion vs. Altamont/Kern River reflect both factors.

With respect to transportation costs, the least-cost alternative for both EOR and utility markets in Southern California is, of course, the existing pipeline grid. The least-cost expansion capacity is via the Kern River Transmission line. The PGT/PG&E transport cost to Southern California is about $0.25/Mcf more expensive than Kern River, due largely to the intra-California cost. Transportation from Alberta to Southern California via Altamont/Kern River exceeds that of Kern River alone by the $0.35/Mcf toll assumed for the Altamont pipeline.

Resource costs show a pattern which partially offsets these transportation cost differentials. Initially, Alberta supplies show a $0.20/Mcf cost advantage over Rocky Mountain supplies, although the differential reverses by the year 2000. Both Alberta and Rocky Mountain supplies enjoy a significant resource cost advantage over San Juan and Permian Basin supplies.

When transport cost and resource cost assumptions are combined, the NARG model indicates a requirement for the PGT/PG&E expansion as well as for the Kern River pipeline. Kern River provides an outlet for attractively priced Rocky Mountain supplies to both EOR and Southern California markets. The market growth for Kern River that appears in Figure 3.3 occurs largely in the

EOR market. Kern River shipments to Southern California markets reach significant levels as soon as the line is available. In fact, the NARG model suggests that some Permian Basin and San Juan supplies may be displaced by Rocky Mountain supplies. This result occurs because the resource cost advantage of Rocky Mountain supplies is significantly larger than the transportation cost disadvantage faced by Kern River relative to existing pipelines.

The PGT/PG&E expansion is well placed to meet market growth requirements in Northern California and to provide competitive supplies to Southern California as well. Delivered prices to Southern California via this route are competitive with other supplies.

The question of shipping Alberta gas to Southern California via PGT/PG&E expansion or via Altamont/Kern River is somewhat more difficult to assess using the NARG model. Reference case assumptions indicate a slightly lower transport cost via PGT/PG&E. Even with equal transport cost, Alberta gas on the Altamont line faces an additional difficulty in that it must compete with Rocky Mountain supplies for space in the Kern River line. In the NARG model, this means a resource cost advantage is required sufficient to overcome the transport cost on the Altamont line. Thus, the viability of the Altamont line hinges critically on the relative resource costs of Alberta and Rocky Mountain region supplies.

To the extent that the Rocky Mountain resource base is overstated by the PGC or that supply costs are understated (as represented in the NARG model), the Altamont supplies will be more successful at bidding for space in the Kern River line. Lead times required to develop reserves and put gathering and processing infrastructure in place for Rocky Mountain supplies may also benefit Altamont supplies. Whatever the assumptions, however, it is clear that Alberta gas supplies flowing into Wyoming and then on to a common market will face competition in Wyoming from local supplies. The Altamont/Kern River line presents a significant potential for supply diversity and the inherent competition for markets, adding up to the benefit of California consumers.

3.2 Midwest

Completion of the Eastern Leg of the Alaska Natural Gas Transmission System (ANGTS) Prebuild section in the early 1980s provided access for exports of Canadian natural gas directly into the U.S. Midwest. This portion of the prebuild includes the facilities of

Foothills Pipe Lines (the Canadian portion) and Northern Border Pipeline (the U.S. section) with the terminus of Northern Border occurring near Ventura, Iowa. Flows on the East Leg of the Prebuild remained significantly below capacity for a number of years after completion for various reasons. However, the past few years have seen near capacity flows at certain times of the season. Recently, expansion and extension have been proposed. Canadian gas can also flow into the Midwest via the TransCanada Pipeline (TCPL) system into Great Lakes Gas Transmission. The Great Lakes Gas Transmission system is mainly a southern arm for TCPL as much of the gas it transports is imported back into Southern Ontario from the U.S.

As the NARG model aggregates demand to the level of U.S. census regions, it is important at this point to indicate which regions are being referred to when speaking of the Midwest. The model represents the general area of the Midwest as two demand nodes, the East North Central demand region and the West North Central and Mountain demand region. The latter is actually an aggregation of two U.S. census regions (as described in Appendix C). The focus here will be upon the general trends within the overall region we have referred to as the U.S. Midwest, although some results are presented separately for the two demand regions.

For the Midwest as a whole, gas demand is approximately 13 Bcf/d (about 4.8 Tcf/yr) at the present time. The expectation regarding future demand is for some short-term growth followed by a significant slackening in demand over the longer term. Underlying this general trend, however, are slight increases over the long-term in the noncore sectors, the switchable market. The noncore market includes electric generation, industrial uses and a portion of commercial application. This may suggest that gas can be competitive and gain market share over alternative fuel sources as overall growth in these applications in the Midwest is likely to be quite stagnant. However, one must remember that regulation and contractual obligations may in reality prevent such outcomes, which are dependent upon competitive assumptions.

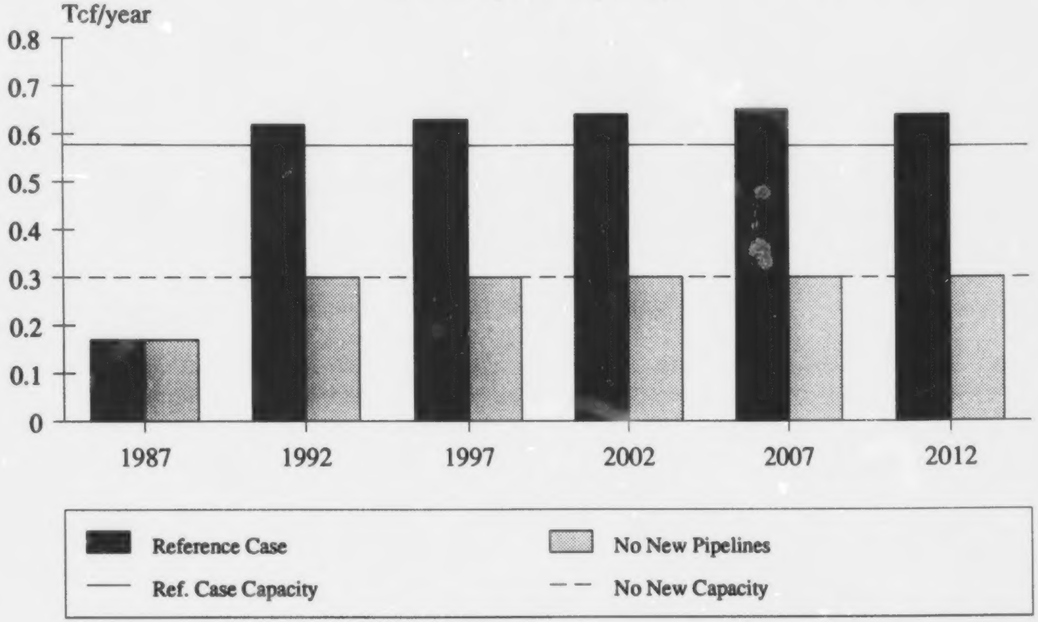
Of interest in this study is the effect of increased pipeline capacity to deliver gas to the Midwest region over the period of interest. The reference case results have indicated that increased pipeline capacity to the Midwest will generate some demand growth. As before, with respect to the California results, the increased supplies generate competition and prices which are lower than would be the case with no expansion. However, the most striking result of the analysis for the Midwest region is the impact upon Canadian natural gas exports in the absence of pipeline expansion. Most significant is the impact in the East North Central demand region into which the Northern Border extension is proposed. Under the assumptions of the reference case, natural gas exports to the East North Central region are essentially twice as large by the end of the study period (to 640 Bcf/yr) when compared to a case which restricts flows to existing pipeline capacities. As shown in Figure 3.4, Canadian exports to this region decline after reaching capacity in 1992 without the proposed extensions. In way of explanation, the large jump in exports between 1987 and 1992 arises due to flows in 1987 being markedly below capacity.

The results presented in Figure 3.4 suggest that expansion is necessary to maintain, over the longer term, the increase in exports observed in the short term (demand levels in both cases rise substantially to 1992). This has significant implications. First, it is suggested that Canadian exports could be competitive in the long term in the East North Central region, given the pipeline extension as it is currently being proposed. Further, if one remembers that demand is generally declining in this region, it is possible that competitively priced Canadian natural gas could even gain market share in gas on gas competition in the East North Central region relative to other supply sources. Similar conclusions can be drawn for the West North Central and Mountain region although the results for that region are not as dramatic.

A further result of the analysis is that, as with the California results, Canadian natural gas exports (in the reference case) show relatively consistent flow levels across almost all of the scenarios examined. Again, as with California, the indication is that Canadian gas can be competitive with other gas supplies to the Midwest under a wide range of resource availability assumptions. The only condition that significantly reduces Canadian exports to the demand regions of the Midwest is, again like the California results, the availability of Canadian frontier resources. As shown in Figure 3.5, when Canadian frontier resources in the Mackenzie Valley are restricted from flowing, exports to the Midwest are reduced by approximately 15 percent by the end of the study period. Again, the importance of a future transition to frontier supplies is demonstrated. As before, flows are restricted in all time periods when frontier supplies are restricted. As explained, this is likely a result of the model's clairvoyant decision-making processes.

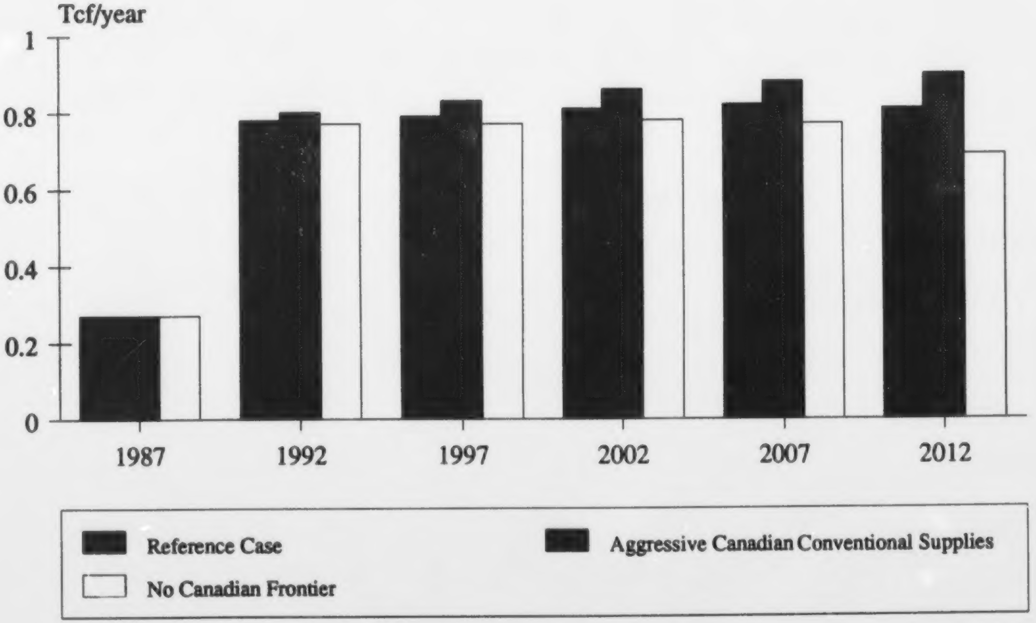
Figure 3.4

Pipeline Impacts on Natural Gas Exports to the East North Central Region and Export Capacity



Source: Table B.26.

Figure 3.5
Resource Impacts on Canadian Natural Gas
Exports to the Midwest



Source: CERI.

Increasing the Canadian resource base by way of more aggressive assumptions has the significant impact of raising the level of Canadian exports to the Midwest by over 10 percent by the end of the study period. This again displays the potential competitiveness of conventional Canadian natural gas in this market and gives an idea of the response of the market to larger than expected Canadian reserves. This result is shown in Figure 3.5. Again, the large increase observed in exports between 1987 and 1992 is partly a function of the relatively poor levels of exports in 1987.

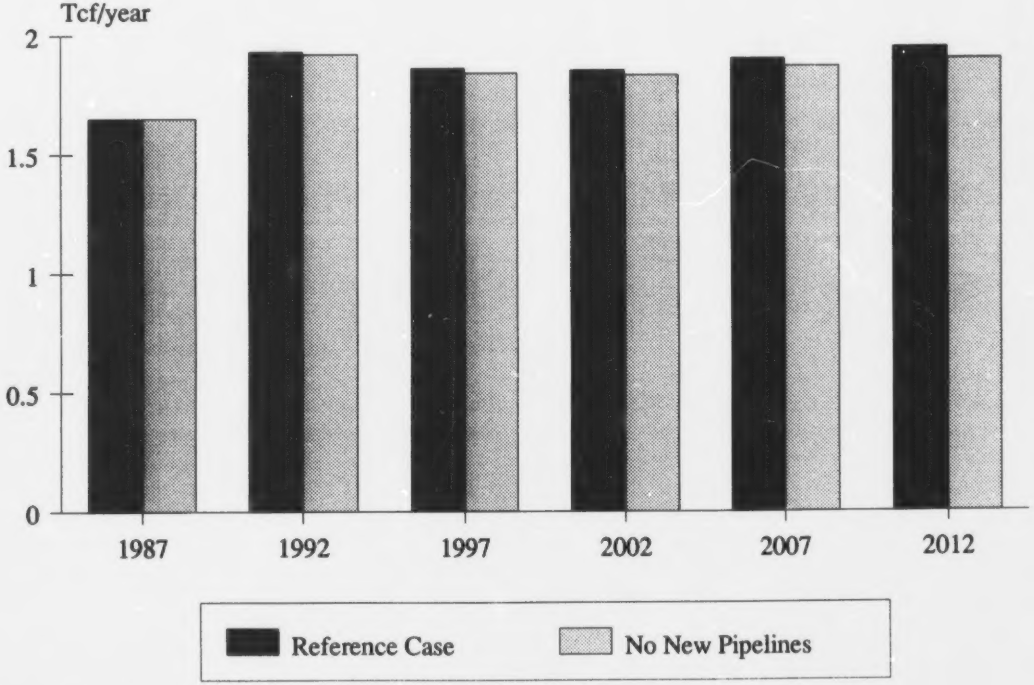
3.3 Mid-Atlantic and New England

The lure of the Mid-Atlantic and especially the New England demand regions for producers of natural gas is the relatively low levels of market penetration for natural gas historically, especially in core markets. This has arisen largely because these regions are the farthest away from the supply areas and thus natural gas has a more difficult time competing with alternatives due to transportation costs. Again it is stressed that the results for these regions, as with those regions discussed previously, are dependent upon assumptions made with respect to competition in the marketplace. For the Mid-Atlantic and New England regions in particular this is important to keep in mind when analyzing the model results.

Recently, demand for natural gas in the New England and Mid-Atlantic regions has been approximately 1.1 Bcf/d (400 Bcf/yr) and 4.5 Bcf/d (1650 Bcf/yr), respectively. Demand growth is expected in the near term with increased penetration into residential and commercial heating markets and commercial and industrial cogeneration applications. Growth is also foreseen in the electric generation sector, as natural gas-fired turbine generation has advantages over coal-fired plants (which require large initial capital investments and which may face environmental siting problems), oil-fired plants (which are believed to be less favourable from environmental and security of energy supply standpoints) and nuclear facilities (which currently face major opposition in these regions). As mentioned, an analysis of increased gas use as a result of changes in environmental regulations pertaining to environmental emissions has not been carried out in this study.

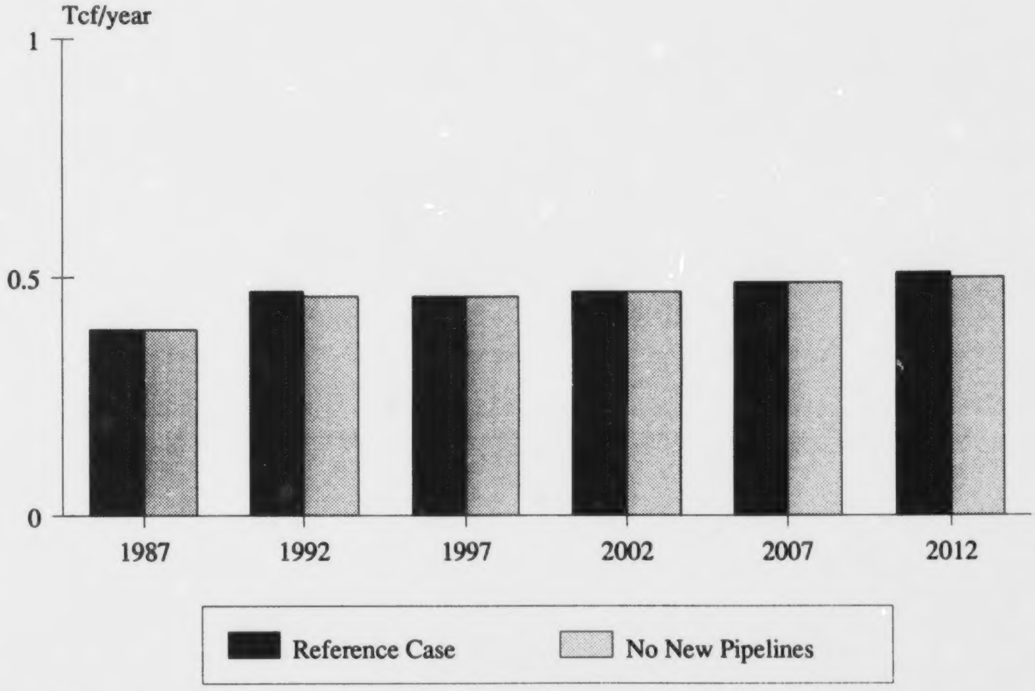
Reference case results show demand in the Mid-Atlantic and New England regions climbing significantly in the near term and then growing slowly thereafter to the end of the study period. This is shown in Figures 3.6 and 3.7, respectively. Notice in these figures that

Figure 3.6
Natural Gas Demand in the Mid-Atlantic



Source: Table B.33.

Figure 3.7
Natural Gas Demand in New England



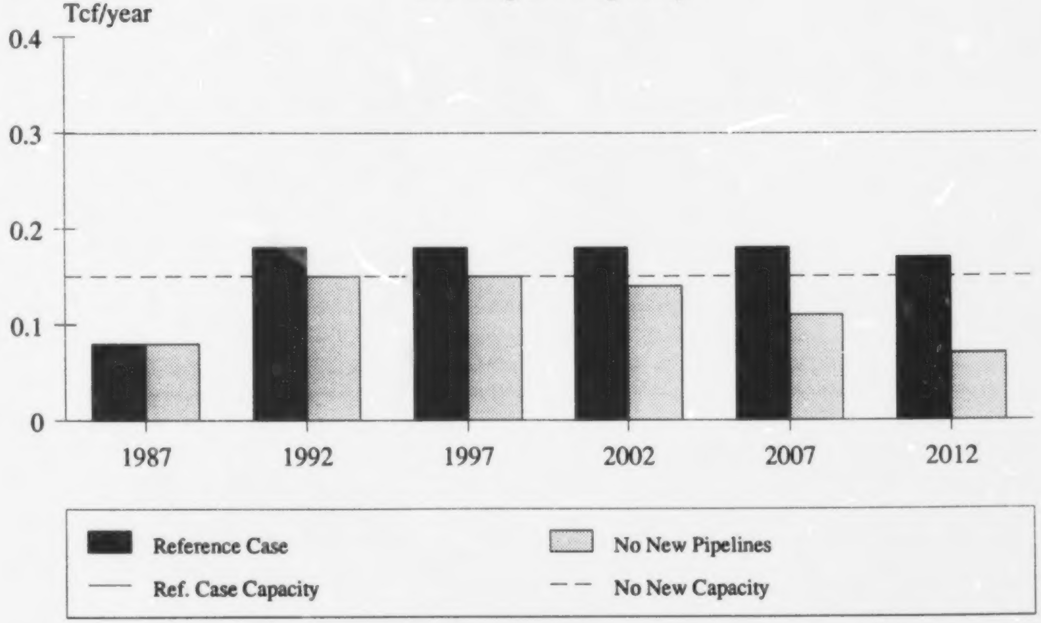
Source: Table B.34.

demand is not reduced much under the no expansion assumption case, especially in New England. If demand is not altered significantly when the proposed pipeline expansions are implemented, then what is the effect upon Canadian exports? Figures 3.8 and 3.9 contrast the reference case and the no expansion case. Figure 3.9 shows no export flows at all as no export capacity currently exists to this region directly. The results are dramatic in terms of their impact upon Canadian exports to these regions. Some observations can be made. First, if expansion is carried out, Canadian reserves can be competitive and Canadian exports can be expanded, especially in the Mid-Atlantic. However, under the reference case, exports to New England do not reach levels high enough to fill a new pipeline. This, and unresponsive demand, indicate that this market will be one of considerable competition and suggest that producers will not favour this market. Figure 3.7 shows that when Canadian export capacity into New England is restricted, natural gas supplies are sourced from elsewhere as demand for natural gas is relatively unaffected.

These points are reinforced when one examines important resource base impacts such as greater than expected Canadian conventional resources or the No Canadian Frontier case. Figures 3.10 and 3.11 compare the results in these cases to the reference case. Notice especially those results given for the New England region in Figure 3.11. The conclusion reached with respect to the New England region is that exports of Canadian natural gas to this region may be supply constrained if Canadian conventional resources are not greater than expected, or if a transition cannot be made for whatever reason to frontier resources in the Mackenzie Valley.

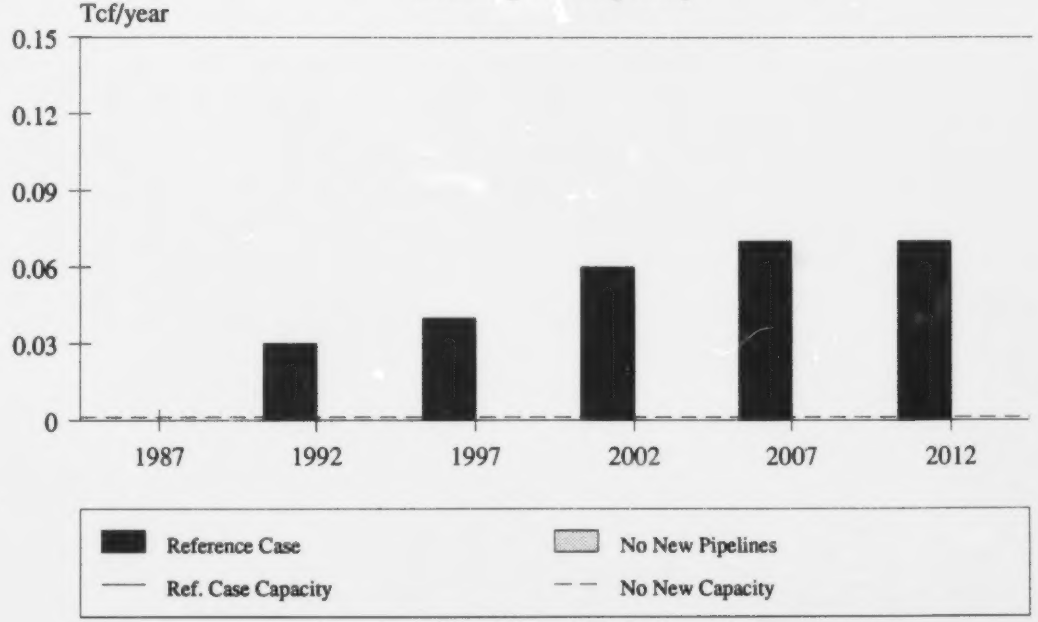
Other interesting observations made with respect to the Mid-Atlantic and New England demand region reinforce what has already been suggested. Examination of cases in which elements of the U.S. resource base are less than expected result in increased levels of export for Canadian natural gas. Higher than expected levels of U.S. natural gas resources result in much lower levels of Canadian exports. Again, the impact is greatest in the New England demand region where variations on the U.S. resource base have significant impacts on Canadian exports of natural gas to that region. For example, the aggressive infill drilling case lowers Canadian exports to New England by over 40 percent by the end of the study period. A case in which the U.S. conventional resource base is modelled at lower than expected levels results in an increase in Canadian exports to New England of over 70 percent. The asumption made with respect to

Figure 3.8
Pipeline Impacts on Canadian Natural Gas
Exports to the Mid-Atlantic
and Export Capacity



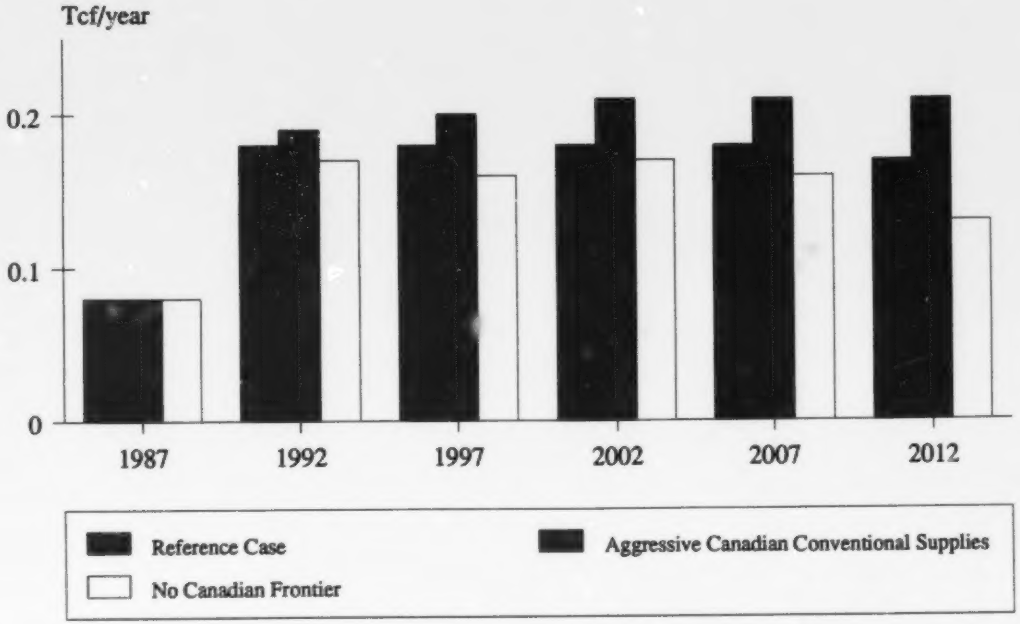
Source: Table B.27.

Figure 3.9
Pipeline Impacts on Canadian Natural
Gas Exports to New England
and Export Capacity



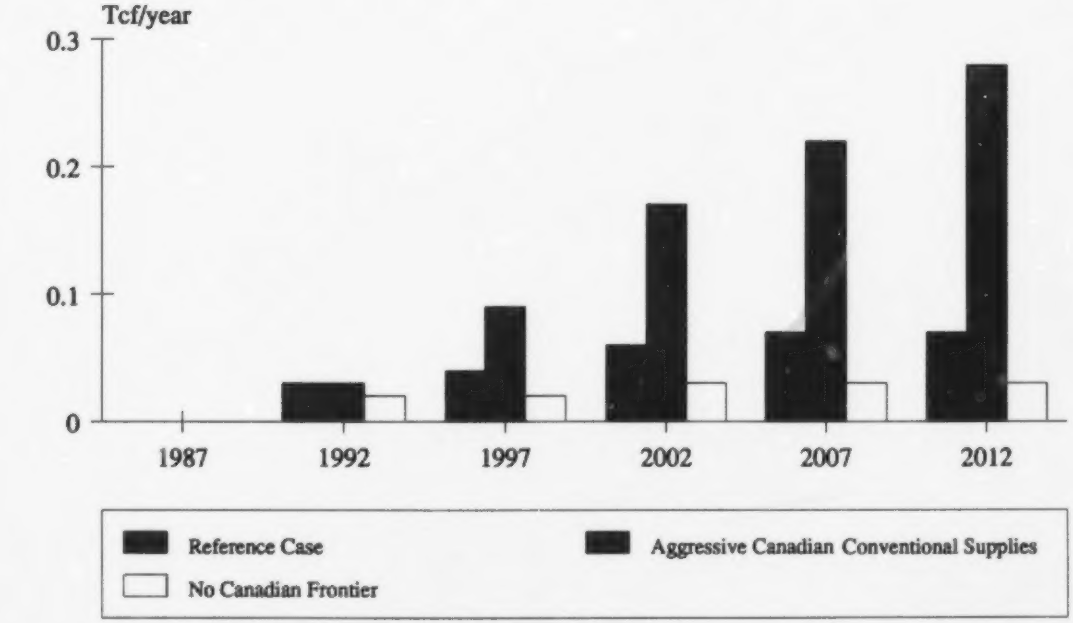
Source: Table B.28.

Figure 3.10
Resource Impacts on Canadian Natural Gas Exports to the Mid-Atlantic



Source: Table B.27.

Figure 3.11
Resource Impacts on Canadian Natural Gas Exports to New England



Source: Table B.28.

Appalachian supplies is particularly import in this regard. Almost as significant is a lower than expected natural gas resource in the offshore Gulf Coast. Canadian exports to New England increase in this case by over 55 percent at the end of the study period, in comparison to the reference case. It is stressed again that these results were obtained under assumptions of a perfectly competitive gas market within these regions. Therefore, the focus should not be on magnitudes but upon the general impacts of these cases.

3.4 The Canadian Resource Base

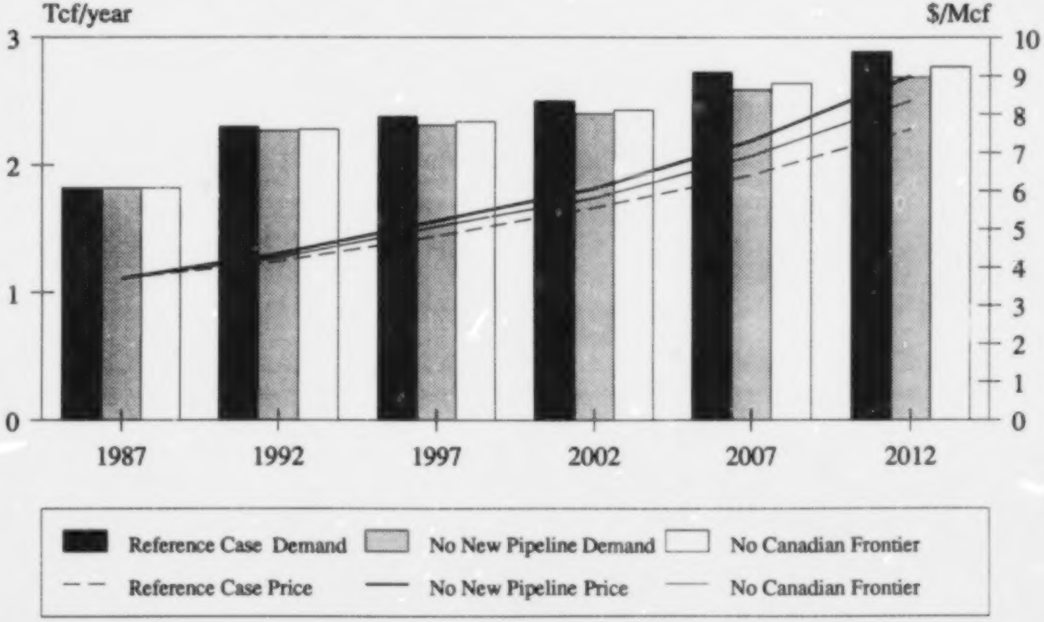
The key uncertainty in discussions of future Canadian natural gas developments is the adequacy of the Canadian natural gas resource base to meet Canadian requirements, if large volume exports of natural gas are permitted. Concern has often been expressed that increased exports of natural gas in the near term will force Canadian consumers to use higher cost resources sooner. The argument has been that exports of natural gas impose a cost on Canadians equal to the cost of having to go to the higher cost resources sooner. This cost has been referred to as a user cost. Some light may be shed on this issue as a result of this analysis.

Total Canadian natural gas demand is compared in Figure 3.12 for the Reference case, the No New Pipeline expansions case, and the No Canadian Frontier gas case. Obvious immediately is that Canadian demand is higher when pipeline expansion is permitted. Further, Canadian demand is even higher than in the No New Pipeline case under the assumption of No Canadian Frontier supplies from the Mackenzie Valley (see Figure 3.12). This impact is observed in all time periods.

A complex interaction of forces is responsible for this result. Expansion of the existing pipeline facilities may offer some opportunity to more efficiently exploit conventional resources. As export levels rise, greater expenditures are made over a shorter period of time to find and develop new supply sources. Also, a more rapid development of conventional resources results in increasingly expensive supplies. This makes a smooth transition to frontier supplies more important as it occurs sooner than would otherwise be the case. The incremental production required to meet growing exports also acts to help ensure that the minimum threshold level of production to make frontier development economic may occur sooner. Together with increased market competition, the net result is lower prices and increased demand as a result of the above forces. Our analysis does not separate

Figure 3.12

Canadian Natural Gas Demand and Ontario Prices Under Increased Exports



Sources: Table B.21 and B.22.

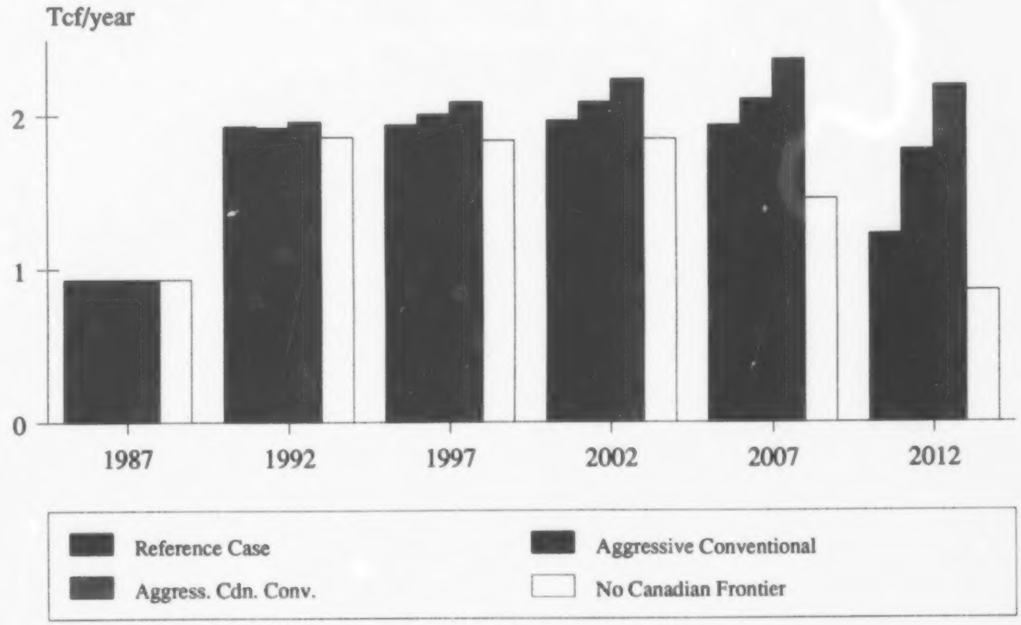
the effects of the various factors described above. Natural gas prices in Ontario under the Reference case and the No New Pipeline case are shown in Figure 3.12 as well. Export expansion is seen by the NARG model to reduce prices and increase demand in Canada in all time periods. It is suggested therefore that the Canadian resource base may well indeed be adequate to support the proposed export capacity expansions, without adversely affecting Canadian consumers. The benefits to Canada of such expansions are discussed in a later section.

Other general observations regarding the Canadian resource base have arisen from the analysis. It is interesting to note that Canadian exports of natural gas are not affected a great deal by variations on the U.S. resource base such as the introduction of coalbed methane or tight gas. These impacts are discussed further in the next section. The greatest impacts upon Canadian exports involve the nature of the Canadian resource base itself. Figure 3.13 shows levels of Canadian exports under various resource assumptions. First, notice that in the Reference case Canadian exports rise significantly by 1992, remaining relatively stable for some time thereafter. However, keep in mind that export flows in 1987 were well below capacity. Also notice that exports decline late in the study period. This effect is dramatically amplified in the case where no Canadian frontier supplies from the Mackenzie Valley are brought on. This suggests that Canadian exports may be significantly constrained without these frontier supplies and that such resources are required to maintain a long-term export capability.

Figure 3.13 also shows that Canadian exports are competitive with U.S. supplies when both are larger than expected. When only the Canadian natural gas resource base is greater than expected, the market life of the conventional Canadian resources is extended further, allowing exports to remain at higher levels longer than in the reference case.

It is also important to look more closely at individual producing areas within Canada and determine the impact upon each region of the various scenarios. Some comments have already been made with regard to the Northern Canadian resource base and its importance to exports. Actually, Northern Canadian production is quite consistent over most of the impact cases analyzed. The most significant impacts upon this resource are assumptions regarding the levels of conventional resources within the U.S. and Canada. Greater than expected conventional natural gas resources in the U.S. or Canada postpone Northern Canadian production until several years

Figure 3.13
Canadian Resource Base Impacts on Exports



Source: Table B.4.

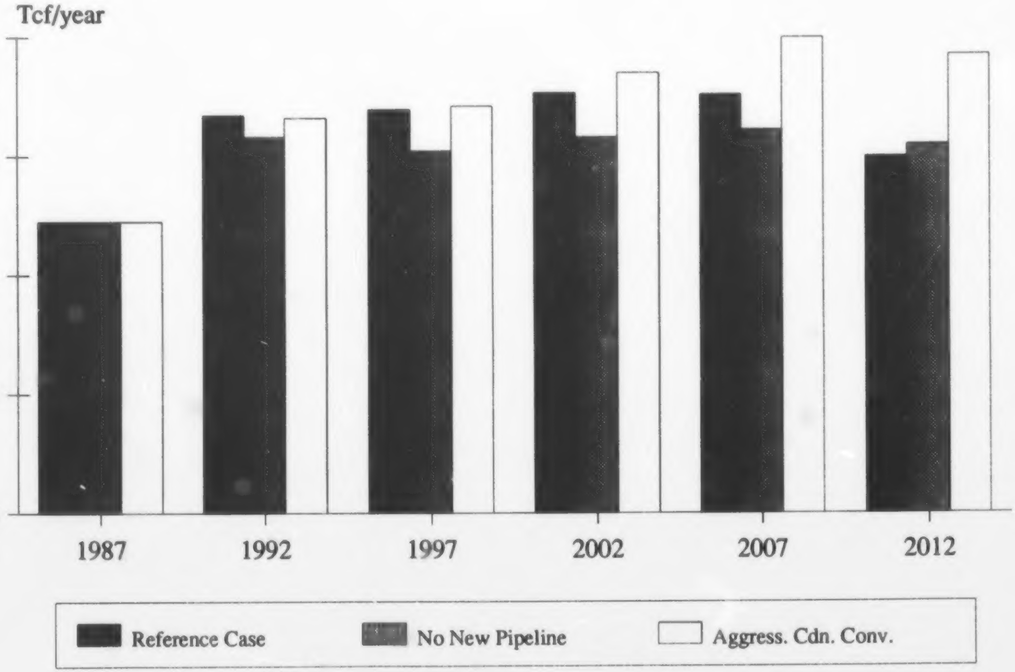
into the next century. A weaker than expected conventional supply could bring on Northern Canadian production approximately 5 years earlier. A reasonable time frame for commencement of delivery of this northern gas, based on the modelling effort, appears to be between 2000 and 2005. However, using more aggressive estimates for the Mackenzie Valley resources suggests that such resources could come onstream during the late 1990s.

Alberta, containing the largest share of the Canadian conventional natural gas resource base, has been exporting large volumes of natural gas to the U.S. for a number of years. The outlook for Alberta natural gas production in the Reference case is for significant growth in the near term followed by lower but continued growth. Toward the end of the study period, natural gas production in Alberta is expected to decline. This is illustrated in Figure 3.14 along with the key impacts upon natural gas production within Alberta, those being greater than expected Canadian conventional resources of natural gas (most of which is in Alberta), and no export expansion. Notice that even in the Aggressive Canadian Conventional supplies case, Alberta's production declines toward the end of the study period. It should be noted at this point that, while Alberta production rises substantially under the reference case, wellhead prices are dramatically lower when pipeline expansion is permitted. Again, this follows from the competitive assumptions of the model.

For the other impact scenarios carried out, Alberta's production remains quite unaffected. This is to say that production of Alberta's conventional gas resources is largely unaffected by lower or higher than expected U.S. conventional resources, infill drilling in the U.S., lower or higher than expected U.S. Gulf Coast resources, coalbed methane impacts, lower or higher than expected Rocky Mountain resources, or tight gas impacts. Alberta production also remains quite unchanged if Canadian frontier supplies are brought on. As demand adjusts to the higher prices resulting from not introducing the Northern Canadian frontier resources, Alberta's production is even reduced somewhat.

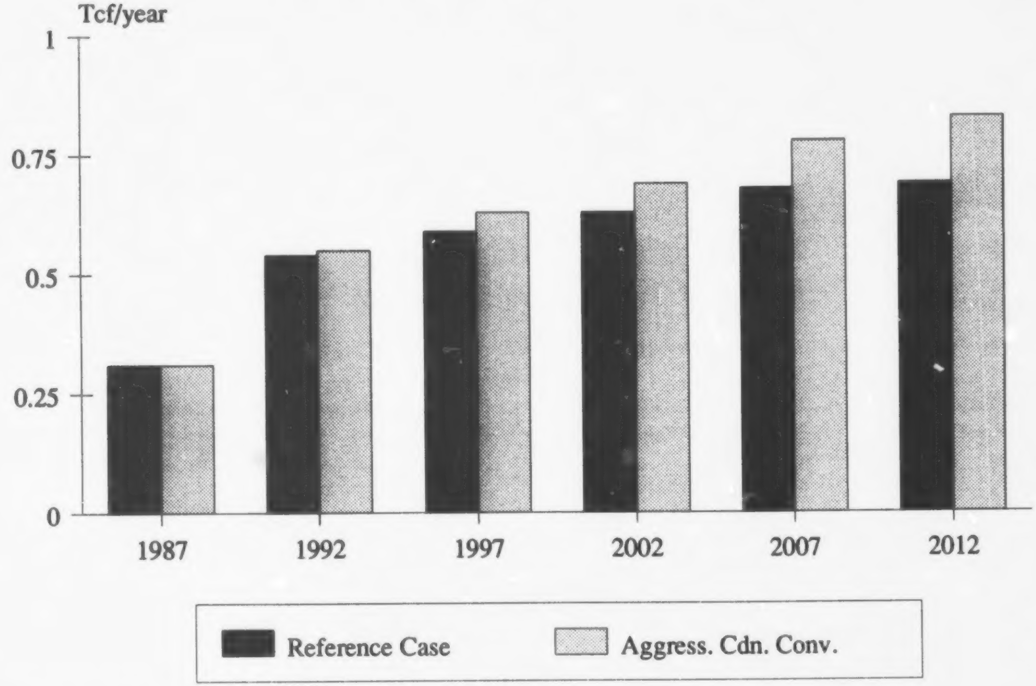
The two remaining supply regions within Canada are British Columbia and Saskatchewan. A most interesting result in the case of British Columbia is that B.C. production remains virtually unchanged when no pipeline expansion is allowed. This suggests that growth in B.C. gas production may not be dependent upon the pipeline expansions proposed. Perhaps this is because current B.C. exports to the Pacific Northwest are significantly below capacity. Thus, room

Figure 3.14
Alberta Natural Gas Production



Source: Table B.14.

Figure 3.15
British Columbia Natural Gas Production



Source: Table B.13.

does exist for increased B.C. production and exports in a physical capacity sense. In Figure 3.15 the reference case results for B.C. production are compared with those for the Aggressive Canadian Conventional case (which includes increased B.C. conventional resources). It is suggested on the basis of these results that significant upside potential exists for B.C. natural gas resources.

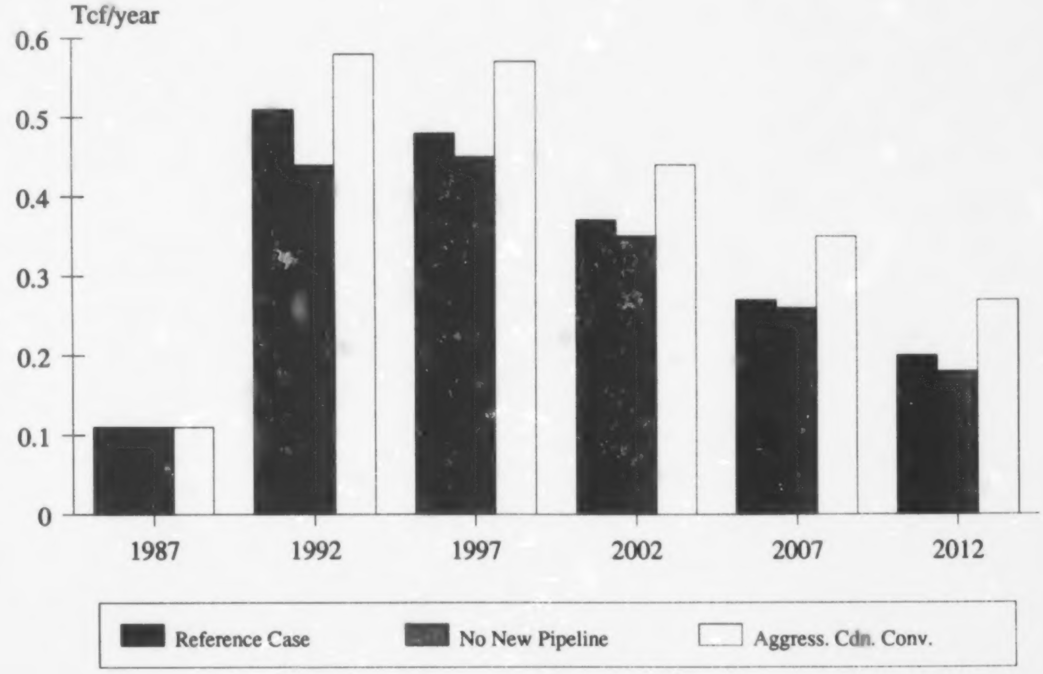
Finally, Saskatchewan production displays substantial growth in the near term followed by relatively large declines over time (see Figure 3.16). Examination of Figure 3.16 leads to a few important conclusions with regard to the resource base in Saskatchewan. For instance, it is suggested that in the short term Saskatchewan production will be sensitive to the expansion of export pipeline capacity as one compares the Reference case to the No New Pipeline case. However, most striking in the analysis is the decline in the longer term, suggesting that, while much more Saskatchewan gas may easily find markets in the near term, the resource base may be too small to sustain these larger levels of production over time.

3.5 U.S. Resource Base

The natural gas resource base within the United States is generally thought of as being mature. A mature resource base is commonly thought of as one which has been extensively explored and developed such that most or all of the major deposits have been discovered and are well along in their development. The result is an industry which can generally be classified as one in which costs increase with continued production. A basic assumption here is that the least-cost natural gas resources are exploited first, followed by the next least-cost and so on. Thus, in a mature resource province such as the United States, the probability of coming across large new finds which would greatly reduce costs in an area are considered to be minimal.

The NARG model characterizes the exploitation of natural gas resources in an increasing cost fashion. It is important to be aware of this when analyzing the model results. Resource exploitation in the real world may not always be carried out in this way due to regulation and contractual obligation, but efficient exploitation of the resource base necessitates the production of least-cost resources first. Actions on the part of U.S. regulatory bodies to remove market restrictions, such as price controls, will help to achieve a more efficient development of the remaining natural gas resources within the U.S.

Figure 3.16
Saskatchewan Natural Gas Production



Source: Table B.15.

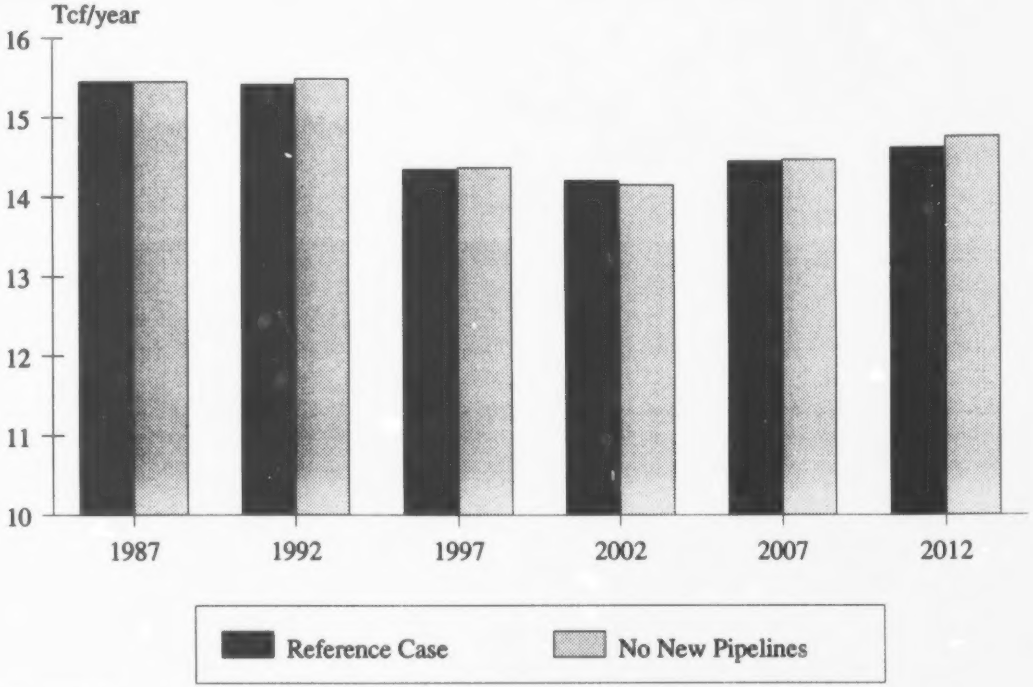
As lower cost conventional resources are exhausted over time and the costs of developing further resources rise, new technologies and unconventional sources of supply become cost effective. At the same time, technological improvements act to lower the costs of such resources. Natural gas resources such as coalbed methane, gas from tight formations, and increased resources obtained through infill drilling look ripe for exploitation to some degree in the future. In addition, it may be that considerable conventional resources may be found in relatively less explored areas such as the Rocky Mountain region or the offshore Gulf Coast.

To put these resource impacts in context comparisons are made with the Reference case. Figure 3.17 compares the Reference case results for Lower-48 production with those obtained in the No New Pipeline case. As the figure shows, while Lower-48 natural gas production is up slightly without increased Canadian exports facilitated by the expansion proposals, demand growth from lower prices under the reference case almost offsets the effect of increased Canadian exports on U.S. production. In comparison, the most significant impacts upon U.S. Lower-48 natural gas production are variations upon the conventional resource base. While the analysis of the conventional resource base does include Canadian resources, the results are significant in terms of their impact upon Lower-48 production. Variations upon the conventional resource base are compared on the basis of their impact on Lower-48 natural gas production in Figure 3.18. Production is reduced markedly if conventional supplies are less than expected, and increases markedly if conventional supplies are greater than expected. The impact upon U.S. natural gas demand is depicted in Figure 3.19. In the model simulations, demand was seen to respond to the price changes induced under the various assumptions regarding conventional resources.

Of the overall Lower-48 resource base, two supply regions have been looked at in greater detail. Impacts of smaller or greater than expected resources within the offshore Gulf Coast supply region are given in Figure 3.20. The large variation in the case of the Gulf Coast supply regions points out the great impact possible under the different assumptions for that region. This indicates the overall importance of this region to analysis of the North American natural gas market.

Potential impacts under various assumptions for the unconventional resources considered in this study are presented in Figure 3.21 for infill drilling and gas from tight deposits. The impact of infill

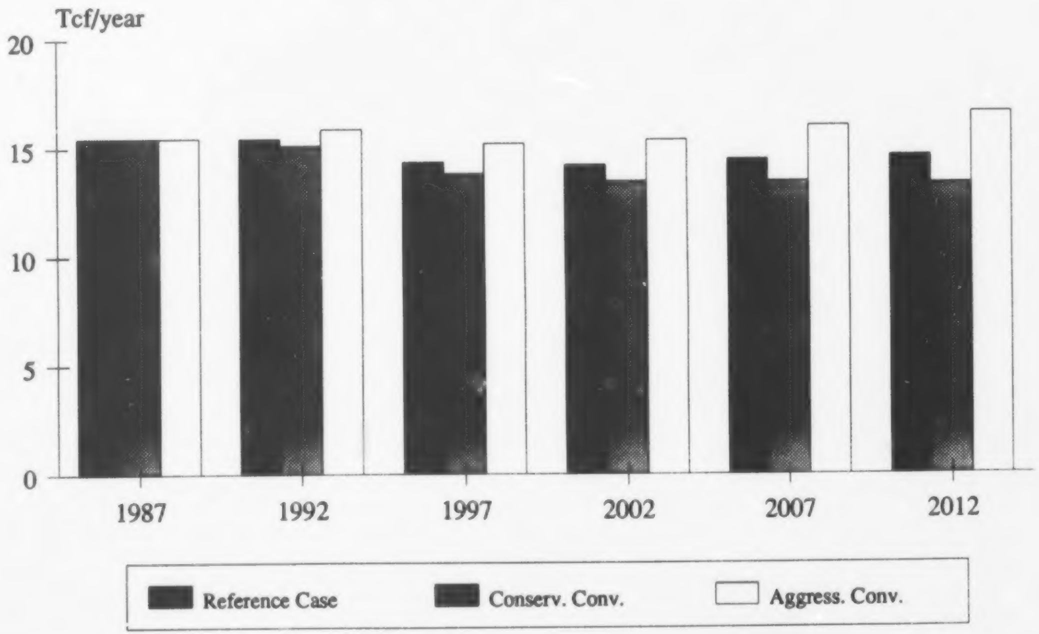
Figure 3.17
Lower-48 Natural Gas Production



Source: Table B.1.

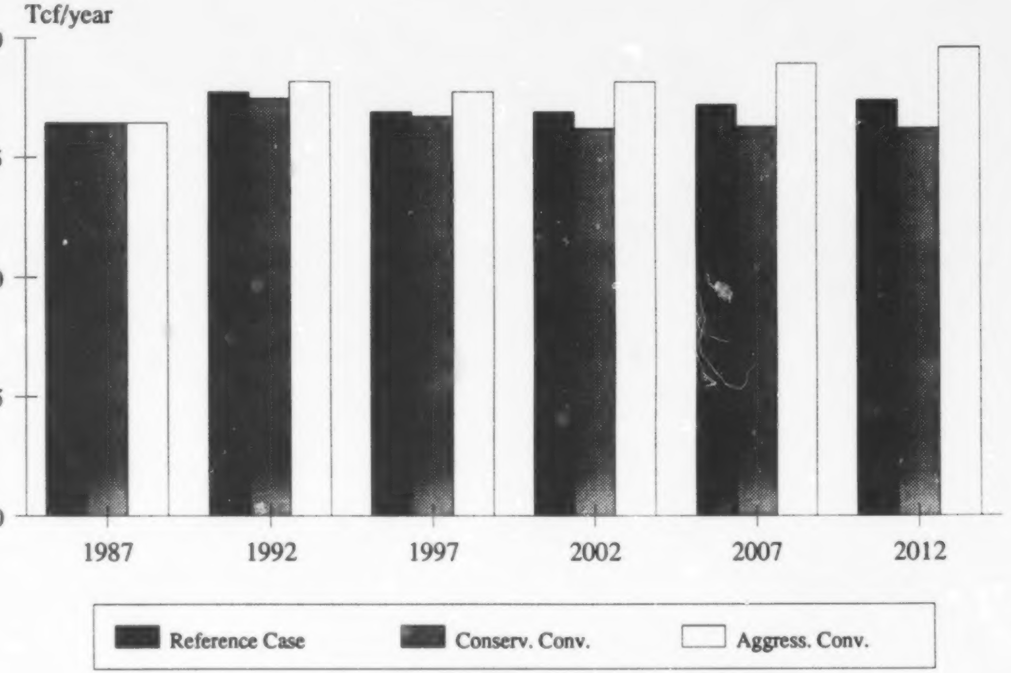
Figure 3.18

Lower-48 Natural Gas Production
Conventional Resource Base Impacts



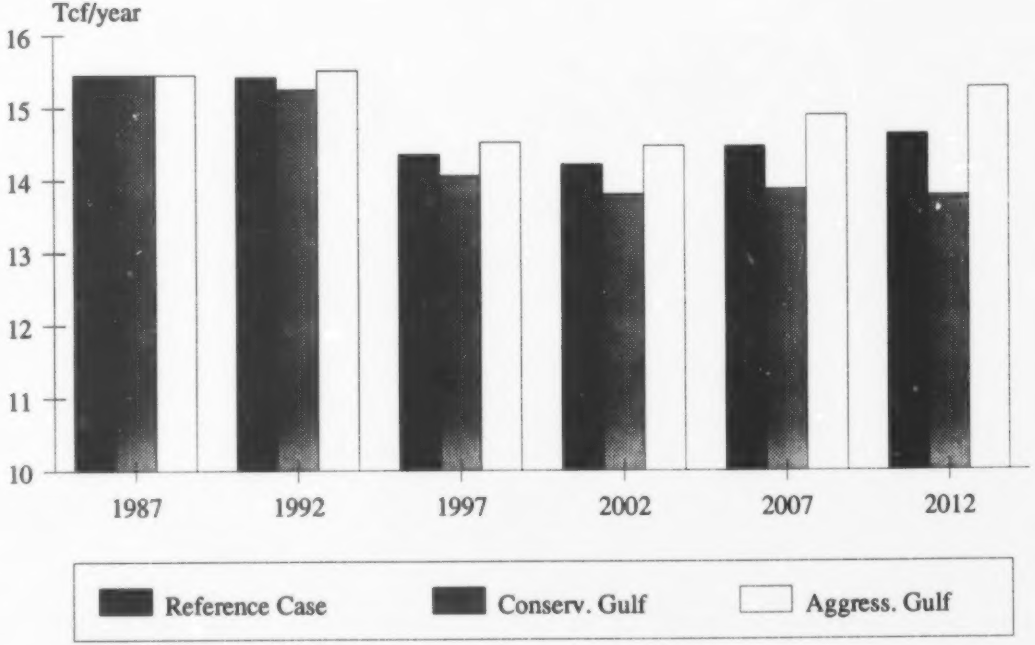
Source: Table B.1.

Figure 3.19
Lower-48 Natural Gas Demand



Source: Table B.8.

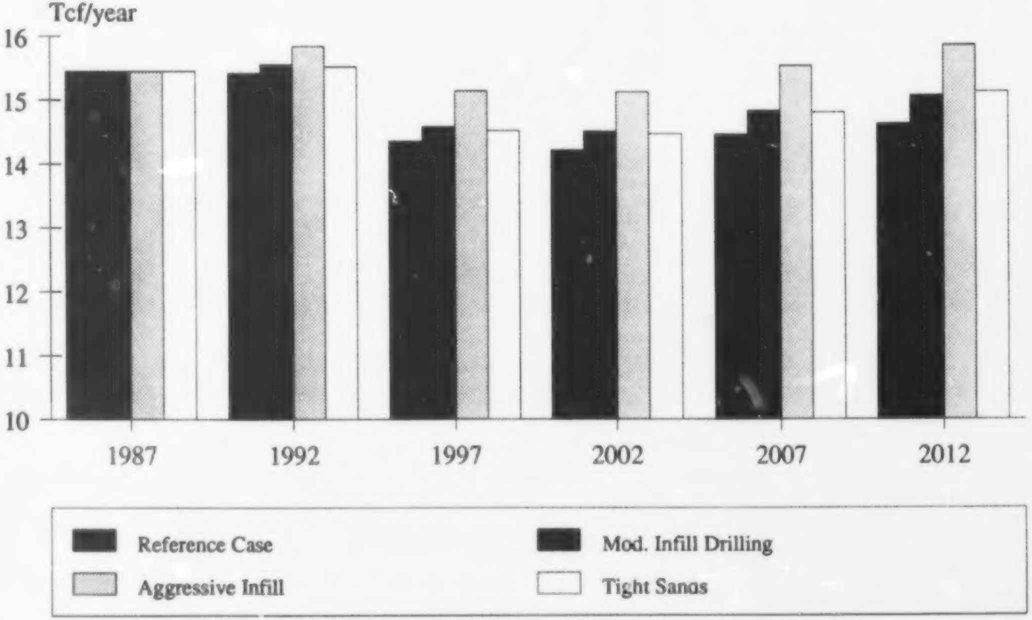
Figure 3.20
Lower-48 Natural Gas Production -
Gulf Coast Impacts



Source: Table B.1.

Figure 3.21

Lower-48 Natural Gas Production - Infill Drilling and Tight Sands Impacts



Source: Table B.1.

drilling upon the model results is significant even in the near term because of the relatively low cost of this resource. In fact, the impact upon total U.S. gas demand in the near term, even in the moderate infill drilling case, is greater than in all other cases except the aggressive infill drilling case and the Aggressive North American Conventional case. Because of their higher costs, the cases analyzing the coalbed methane resource and the tight gas resource do not show substantial impacts until much later in the study period. Also, there is a relatively small difference between the conservative and aggressive coalbed methane cases. This is essentially due to the relatively expensive nature of these resources.

Not discussed to this point is the entry of Alaskan natural gas. Due to the structure of the NARG model and the large resource available in Alaska at moderate cost, once prices reach a level high enough to overcome the transport cost, these resources aggressively come onstream. The model's timing for the Alaskan resource is around 2007. This time frame is quite consistent over all the resource cases, including the conservative conventional case in which conventional resources are modelled to be at levels which are less than expected. Cases in which Alaskan gas flows earlier or later are the No Canadian Frontier case and the two aggressive conventional resource cases, respectively. It is also observed that with a combination of low resource cost assumptions and favourable pipeline economics, the ANGTS system could be advanced by about 5 years. Our reference case, however, reflects a more conservative outlook.

Under the case in which Mackenzie Valley gas does not flow, Alaskan gas comes onstream up to 5 years earlier. Under cases in which conventional natural gas supplies are greater than expected, Alaskan gas flows are pushed back to the end of the study period.

Again, the reader is reminded of the assumptions upon which the NARG model is founded. Conditions as they exist in the real world may result in outcomes much different from those modelled here. However, it is suggested as before that the analysis carried out here provides useful and consistent insights in terms of the potential impacts under various assumptions regarding the U.S. resource base.

3.6 Comparative Economics

This section discusses comparative impacts of the various pipeline configuration and resource base scenarios examined. The focus of comparison is relative price and volume changes, with the

Reference case serving as the point of comparison. The results presented in this section in particular must be reviewed keeping in mind the competitive behaviour assumptions of the NARG model. For example, in a competitive world additional pipeline capacity backed by economically attractive supplies will invariably lead to increased market competition and lower end-use consumer prices. Such results must be interpreted as reflective of input assumptions rather than predictive of future events.

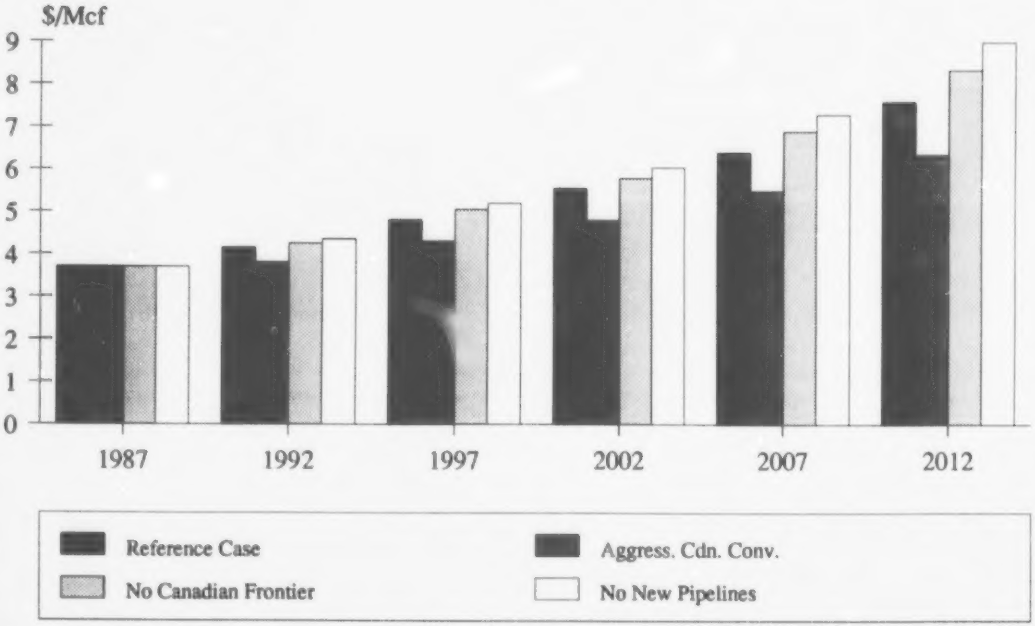
As depicted in Figure 3.22, average Ontario burner-tip natural gas prices rise in real terms throughout the outlook period. A similar trend occurs in other Canadian demand regions. Total Canadian demand is depicted in Figure 3.23. A comparison of the cases shown in Figure 3.22 indicates the significant user cost component of future price growth. When aggressive assumptions are made concerning the conventional natural gas resource base in Western Canada, prices rise much less rapidly than under reference case assumptions. The No Canadian Frontier case indicates the value to Canadian consumers of a smooth transition to Northern Canadian supplies. Making northern supplies available in a timely fashion partially offsets the rapidly rising cost of conventional supplies toward the end of the outlook period.

The price impact of the No New Pipelines case should not be taken as predictive. In this instance, the case indicates that without some pipeline construction, serious capacity bottlenecks will develop in several regions of North America. These bottlenecks will create scarcity rents associated with limited capacity and have the potential of driving prices significantly above current levels. The actual level of future prices in a constrained case will depend in part on whether producers or consumers control available pipeline capacity. Such influences are not explicitly captured by the NARG model.

The above results suggest that once a decision is taken to expand export capacity significantly above current levels, the actual pipeline configuration chosen is less important to domestic consumers than are future resource costs. This may not, of course, be true for U.S. consumers in regions such as New England.

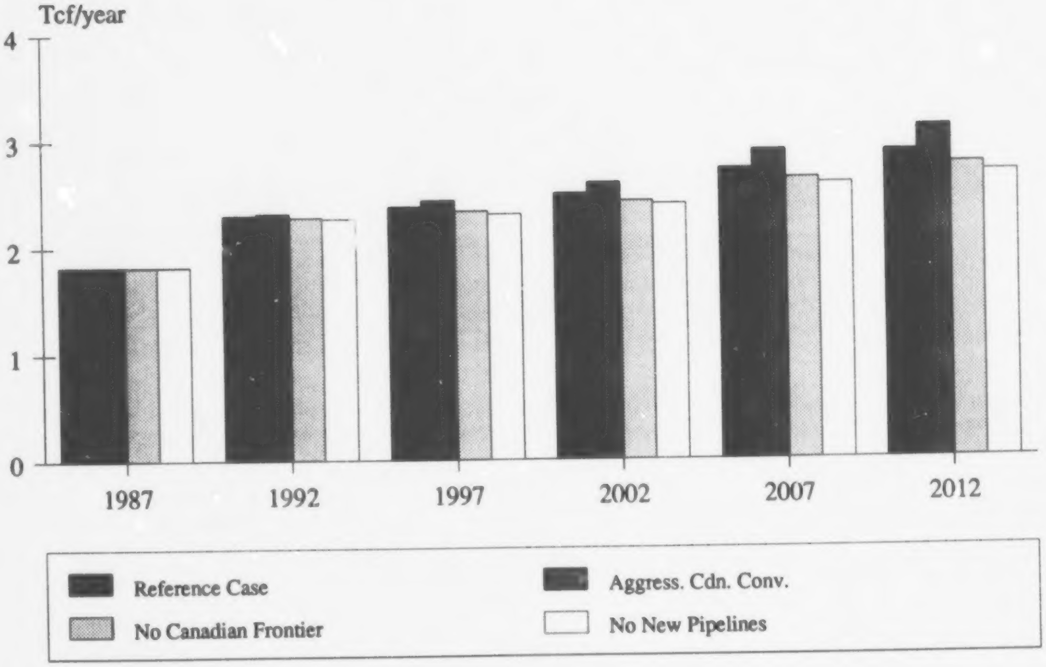
Similar trends are observed for Alberta wellhead prices and Canadian gas production in Figures 3.24 and 3.25, respectively. For Alberta rising wellhead prices are observed across all scenarios. Plentiful conventional supplies reduce user costs resulting in moderated price growth. A smooth transition to frontier supplies around the year

Figure 3.22
Average Ontario Burner-Tip
Natural Gas Prices



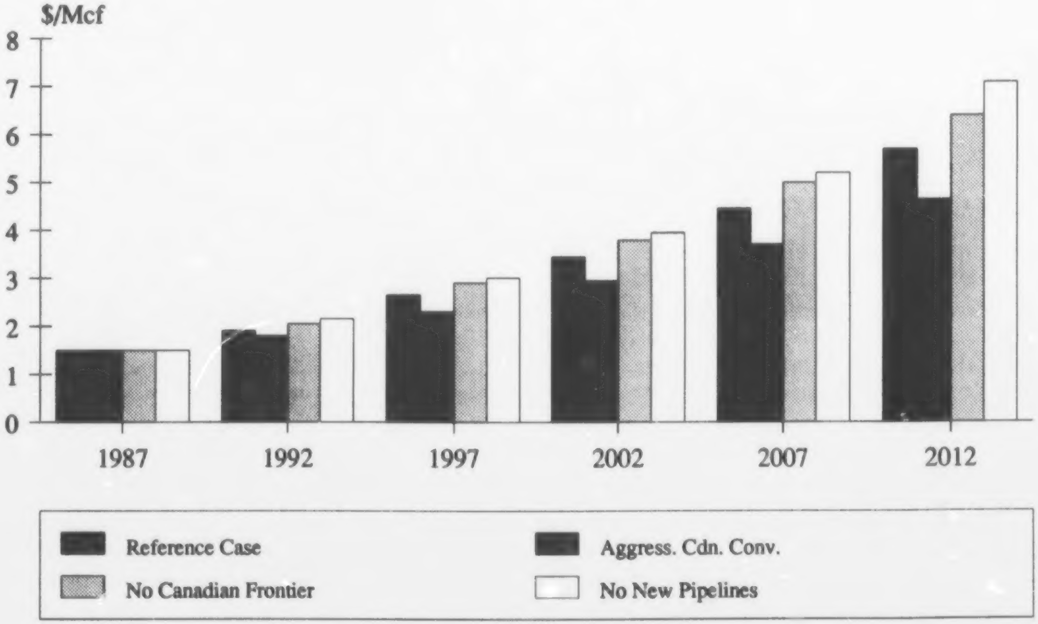
Source: Table B.22.

Figure 3.23
Canadian Natural Gas Demand



Source: Table B.21.

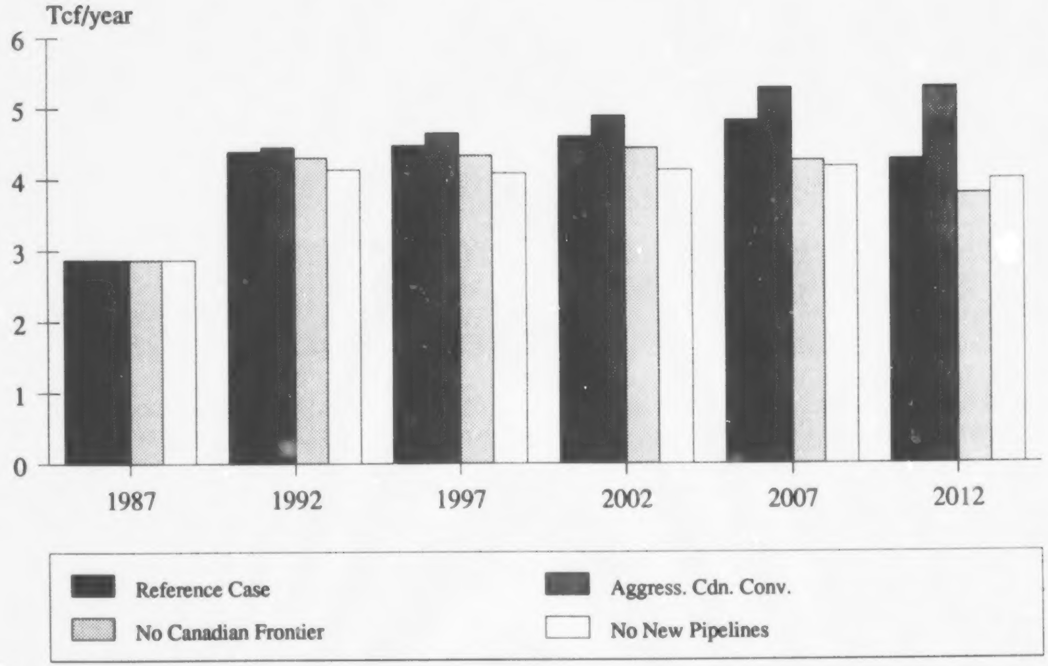
Figure 3.24
Average Alberta Wellhead
Natural Gas Prices



Source: Table B.20.

Figure 3.25

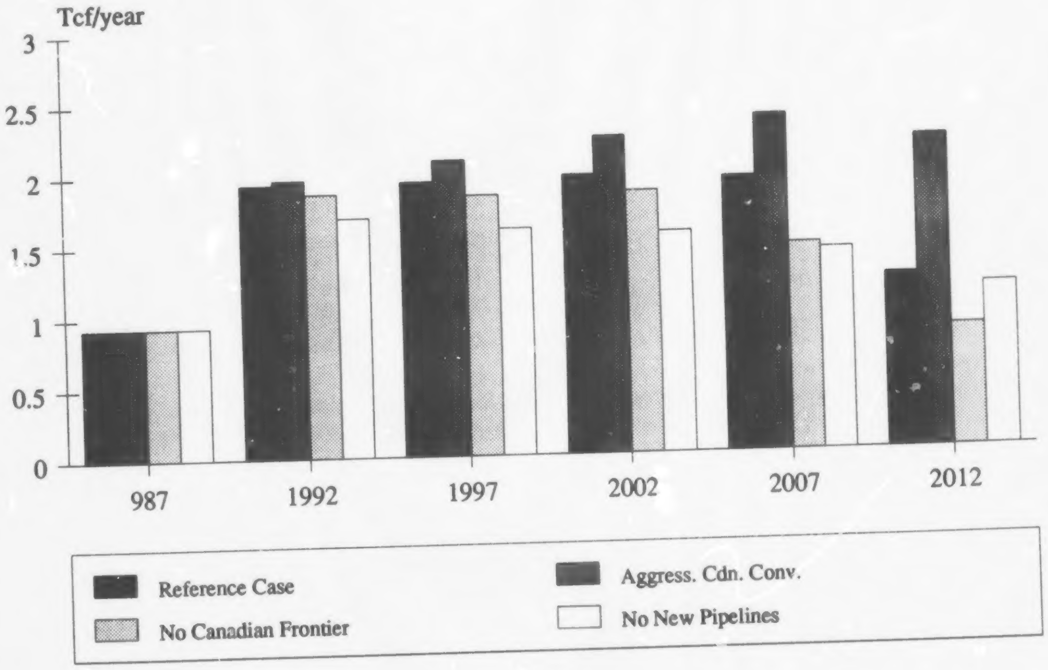
Total Canadian Natural Gas Production



Source: Table B.17.

Figure 3.26

Total Canadian Natural Gas Exports



Source: Table B.4.

2000 is also required to avoid bringing the very high cost conventional resources onstream. Figure 3.25 shows Canadian gas production reaching a level reflecting increased exports, then remaining generally in the 3.5 to 4.5 Tcf/yr range. This result holds across a wide range of future scenarios with resource base assumptions providing the greatest impact.

Canadian natural gas exports, as depicted in Figure 3.26, show significantly more variation across scenarios. The direction of change follows the results above, although the magnitude of the impact is much more pronounced. This result in particular reflects the competitive allocation processes of the NARG model. As we approach the end of the forecast period, or as we modify input assumptions to restrict availability of Canadian gas (both frontier and conventional), we see a significant reduction in export flows. This result is obtained with no explicit restriction on exports. As supplies become more difficult to obtain, exports are reduced significantly more rapidly than is domestic consumption, suggesting that Canadian consumers may be able to rely on market forces to ensure that their future requirements are met.

Chapter 4

CONCLUSIONS

The results presented in Chapter 3 survey a broad range of resource base assumptions and their impact on individual pipeline corridor expansion plans. Only the key results were presented in order to maintain the focus on pipeline corridors. This chapter draws conclusions from those results.

Exports of Canadian natural gas to the United States are in the range of 1.9-2.0 Tcf/yr under a wide range of resource base scenarios, although some shifts in regional export patterns do occur. This represents an increase of over 600 Bcf/yr relative to 1988 levels and suggests that major expansion of export pipeline capacity is warranted. It further suggests that Canadian gas will play an active role in meeting future U.S. natural gas demand, assuming that Canadian producers are granted the regulatory freedom to be competitive.

In order to sustain exports in the 1.9-2.0 Tcf/yr range, one of two scenarios must be realized. The first is an orderly phase in of Northern Canadian (and Alaskan) natural gas supplies. The second scenario would be conventional resource discoveries in the high end of the current range of expectations. Such a case might be brought about by significant increases in wellhead natural gas prices over the next decade, stimulating exploration activity.

The phase in of Northern Canadian supplies will be critical to future Canadian supply potential. Without those supplies, natural gas exports could be reduced by as much as 300-400 Bcf/yr by the end of the forecast period. Such deficits do not appear, however, until after the year 2000. By the end of the study period, exports without Northern Canadian supplies fall below current pipeline capacity, leaving significant pipeline space unoccupied.

When compared to the current pipeline capacity, the expansion projects have an interesting impact on U.S. gas demand. Increased competition in the U.S. leads to lower prices and increased demand.

Natural gas exports to California rise to the 650-700 Bcf/yr range and are relatively stable with new pipeline capacity. In fact, with its purely economic reasoning, the NARG model forced an increase in flows to California even when pipeline capacity was restricted to current levels. This suggests a strong economic incentive in favour of the PGT/PG&E expansion. With the new California capacity turned off, flows to other regions increase somewhat, suggesting a possible preference for the California market.

Even in the face of abundant supplies of Rocky Mountain natural gas, Alberta supplies are competitive in California and will likely continue to provide attractive netbacks and achieve high rates of take. These conclusions may be mitigated somewhat, depending on the premium that is associated with diversity of supply.

With respect to the Altamont/Kern River/Mojave projects, our conclusions are favourable, although somewhat less optimistic. Natural gas supplies in the Rocky Mountain region of the U.S. will be developed over the projection period and will need to penetrate new markets. California will provide an excellent opportunity. Shipments to California via Kern River pipeline will build steadily, requiring full Kern River capacity.

In the early years, however, Alberta supplies via the Altamont line will face a major obstacle. Alberta gas, including transportation to Wyoming, will be required to compete with local supplies for space in the Kern River/Mojave segment of the line. Again, a significant cost disadvantage must be overcome. Resource base developments in the Rocky Mountain region will be a key determinant of the long-term competitiveness of Altamont supplies.

On the positive side, the Altamont/Kern River/Mojave venture does offer a diversity of supply not fully achieved by the PGT expansion or by a stand-alone Kern River. To the extent that security or diversity of supply places a premium value on the Altamont supplies, unfavourable economics may be overcome. Also, any opposition to the PGT expansion on the basis of market power would favour the Altamont/Kern River/Mojave project reaching full volumes earlier in the projection period.

An increased role for British Columbia natural gas exports is also indicated. This results from two trends observed in the marketplace as well as in the NARG model. First, when the option is available to move B.C. gas into Alberta and then south into California, increased flows result, suggesting that B.C. supplies can be competitive in that market. Second, as Alberta gas finds new market opportunities elsewhere, B.C. resumes its role as traditional supplier to the Pacific Northwest, capturing an increasing market share. B.C. gas also faces less pressure from Rocky Mountain supplies to the Pacific Northwest as other markets for Rocky Mountain gas are developed. Thus, our analysis indicates both an increased utilization of Westcoast Energy Inc.'s pipeline facilities and an incentive to develop the B.C. to Alberta flows through the Elmworth and Gordondale lines. These issues will be the focus of a CERI study on British Columbia natural gas developments and opportunities, to be initiated in late 1989.

In summary, we find that the trends developing in the California marketplace are strongly supported by economic forces. The direct PGT expansion line is a preferred route. The Kern River/Mojave link will provide Rocky Mountain gas access to the California market. Expansion to include full Altamont volumes will not likely take place immediately and may face significant competition from Rocky Mountains supplies, perhaps through a WYCAL line. There is evidence to suggest that pursuing both the Kern River and WYCAL projects may result in too much Rocky Mountain to California capacity.

Turning to the U.S. Midwest market, our analysis suggests that expansion of the Foothills-Northern Border system will be required to meet market requirements. The reduced transport costs on that line will be a positive factor. Under a wide range of scenarios examined, it is evident that this line should achieve attractive load factors and will likely be able to avoid the difficulties it has faced in the past. This conclusion is based, however, on the timely availability of Northern Canadian and Alaskan supplies. Without such supplies, or without better than anticipated discoveries in conventional areas, this project could face some long-run difficulties in securing adequate supplies.

The U.S. Northeast market appears to be the marginal market for Canadian gas. Canadian supply costs and U.S. conventional supplies combine to bring this about. When Canadian gas is abundant, exports to New England rise sharply. Conversely, when Canadian supplies are tight due to lack of northern or other frontier supplies or other factors, exports to New England decline sharply. This underlines the importance of low-cost supplies in overcoming transportation costs to reach this market. Further, when U.S. conventional supplies are tight, Canadian exports to New England rise significantly. This indicates that New England is the marginal market for U.S. producers as well.

With regard to the Mid-Atlantic market, Canadian exports are stable across a wide range of future conditions. Here again, if Northern Canadian supplies are not available, significant export curtailments will likely occur toward the end of the projection period.

The above results suggest that the Iroquois project, which will serve principally Mid-Atlantic markets, is well supported by economic forces, although some downside risk does exist. The combined capacity of Iroquois and Champlain to serve the New England market is likely too large. The market appears to require the full capacity of both lines only if the U.S. conventional resource base is less abundant than expected. This suggests that under Reference case circumstances, the Champlain line may continue to experience difficulties obtaining sufficient levels of gas supply.

In Canada, natural gas consumers may benefit from new export pipeline capacity. In fact, domestic gas consumers may be significantly better off with the expanded lines than without. This conclusion rests heavily on the ability of Canadian gas supply to meet the market in terms of both volume and price. In order for the full benefit to be realized, Canadian natural gas prices will need to be flexible enough to reflect the lower prices engendered by competition in U.S. markets.

The Canadian market is also likely to be insulated to a certain degree from minor variations in Canadian gas supply. In other words, Canadian markets are not the marginal destination for Canadian gas supplies. To the extent that prices are set competitively, Canadian consumers will see a benefit from increased pipeline capacity and will be able to obtain required supplies throughout the projection period. This result is obtained without any export approval restrictions and without modelling a Free Trade Agreement impact.

The Canadian natural gas resource base will likely be capable of supporting exports in the range of 2.0 Tcf/yr throughout the next 20 years. This result depends on the availability of Northern Canadian supplies toward the end of the period. It also depends on efficient management of the resource base. Any attempt to impose a particular reserves-to-production ratio through a formula or otherwise could create problems. The resulting cost increase and level of reserves withheld from the market could have a potentially serious impact on the proposed pipeline expansions.

The results also suggest that Northern Canadian supplies will be required at about the turn of the century, and about 5 years before Alaskan supplies can be expected to reach the market. Northern gas could be required 5 years earlier or later, depending on availability of conventional North American supplies.

In summary, the majority of pipeline expansion plans examined in this study are supported by a wide range of future conditions. Certain exceptions relate to specific market areas such as New England, or to such factors as availability of conventional and frontier resources. Availability of coalbed methane, coal gasification and tight gas supplies may be of marginal significance.

From the results discussed above, it appears that the 1990s will be an historic decade for Canada/U.S. natural gas trade. Many of the negative experiences of the 1980s will be replaced by positive results, for both consumers and producers.

APPENDIX A

DETAILED OVERVIEW OF EXPANSION PLANS

- **ALASKA NATURAL GAS TRANSPORTATION SYSTEM**
- **ALTAMONT**
- **CHAMPLAIN PIPELINE PROJECT**
- **IROQUOIS**
- **KERN RIVER**
- **MACKENZIE VALLEY PIPELINE**
- **MOJAVE**
- **NORTHERN BORDER EXPANSION**
- **NOVA EXPANSION**
- **PGT EXPANSION**
- **TCPL EXPANSION**
- **WYCAL**

Appendix A

DETAILED OVERVIEW OF EXPANSION PLANS

This appendix provides summary tables for each of the pipeline projects considered in this study. The data are taken from FERC filings, NEB applications, press releases, newspaper articles, trade publications and telephone contacts. Every effort has been made to ensure completeness and accuracy, although the final results will, of course, not be known until the pipelines are built and operating.

In addition to the major expansions described in this appendix, minor adjustments to the U.S. transportation grid are curently being undertaken or are planned. Such projects are largely to remove bottlenecks and improve the flexibility and use of existing pipelines.

PROJECT NAME: ALASKA NATURAL GAS TRANSPORTATION SYSTEM

Description: Pipeline to carry Alaskan and Arctic/Mackenzie Valley natural gas to the U.S. via Foothills Pipe Line and other interconnecting lines.

Capital Cost: $14.6 billion (U.S. $1988) (7.2 Alaska/5.6 Canada/1.8 Lower-48).

Distance: N/A

Projected In-service Date: Late 1990s.

Status of Application: Approved.

Sponsors/Shares:

Foothills Pipe Lines Ltd.

Tariffs:

(Prudhoe Bay to Lower-48 city gate.)

	Full COS	Levelized
5 yr. Avg.	$3.80/MMBtu	$3.05
10 yr. Avg.	$3.05	$3.05

Shippers/Suppliers/Volumes: N/A

Major New Interconnections:

Location	Company	Capacity	In/Out
Caroline	Foothills Pipeline	2.3 Bcf/d	Out

Physical Capacity:

2.3 Bcf/d. initial, expandable with compression to take 1.2 Bcf/d from Mackenzie and over 3 Bcf/d from Prudhoe Bay.

PROJECT NAME: ALTAMONT

Description: Producer sponsored pipeline to carry Alberta gas to an interconnection with the Kern River line. The eventual destination is the California EOR/Utility market.

Capital Cost: $580 million ($U.S. 1989).

Distance: 620 miles of 30" pipe (Alberta border to Opal, WY).

Projected In-service Date: Late 1993.

Status of Application: Filed with FERC July 1989.

Sponsors/Shares:

Amoco Canada	33%
Shell Canada	33%
PetroCanada	33%

Tariffs: $0.85/Mcf (Alberta border to Southern California).

Shippers/Suppliers/Volumes:

Southern California Gas Company	Pacific Interstate Company	200 MMcf/d
Altamont Sponsors		300 MMcf/d

Major New Interconnections:

Location	Company	Capacity	In/Out
Alta/Montana Border	NOVA	700 MMcf/d	In
Opal, Wyoming	Kern River/Wycal	700 MMcf/d	Out

Note: The interconnection with Kern River will initially be limited to 200 MMcf/d. Expansion of Kern River will be required to reach full Altamont volumes. Initially, Altamont volumes are to flow through Northwest Pipeline.

Physical Capacity:

700 MMcf/d.

PROJECT NAME: CHAMPLAIN PIPELINE PROJECT

Description: A pipeline interconnecting with TCPL in Quebec. It will deliver gas through Vermont, Southwestern New Hampshire, and Massachusetts (into Boston). Major customers are gas and electric utilities.

Capital Cost: $313.64 million in 1991 and $40.46 million in 1992.

Distance: N/A

Projected In-service Date: 250 MMcf/d - Oct. 31/1991, 430.6 MMcf/d Oct. 31/1992.

Status of Application: Currently under environmental review.

Sponsors/Shares:

Northern New England Gas Corporation	15%
Noverco	15%
Central Vermont Public Service Corporation	15%
Providence Energy Corporation (Resource Monitors Inc.)	2%
Algonquin	25%
ANR	28%

Tariffs:

	Minimum		Maximum	
	Reservation Per Month	Commodity	Reservation Per Month	Commodity
Firm Zone 1	6.41	.01	6.41	.0966
Firm Zone 2	12.40	.01	12.40	.1893
Int. Zone 1	-	.2207	-	.3074
Int. Zone 2	-	.4177	-	.5970

- all rates $/MMBtu.

Shippers/Suppliers/Volumes:

Shipper	Supplier	Max. Volume (MMcf/d)
Algonquin Gas Transmission Company	Pan-Alberta Gas Ltd.	50.6
Altresco Lynn, Inc.	Vector Energy Inc.	40.0
Berkshire Gas Company	WGML	5.0
Boston Gas Company	Esso Resources Canada Ltd.	35.0
Coastal Power Corporation	Various Cdn.	30.0
Colonial Gas Company	Pan Alberta Gas Ltd.	7.0
Colonial Gas Company	Direct Energy Marketing Ltd.	5.0
Commercial Union Energy	Direct Energy Marketing Ltd.	14.0
Dartmouth Power Associates	Brymore Energy Ltd.	35.374
Energy North Natural Gas	WGML	5.0
Enertrac Corporation	Direct Energy Marketing Ltd.	1.197
Essex County Gas Company	WGML	2.02
Granite State Gas Transmission	Shell Canada Limited	23.0
New England Power Company	N/A	25.0
New England Power Company	Sceptre Resources Ltd.	20.0
New England Power Company	Triton Canada Resources Ltd.	15.0
Nordic Power of Montague	Pan Alberta Gas Ltd.	30.0
Pepperell Power Associated	WGML	9.4
Providence Gas Company	Pan Alberta Gas Ltd.	30.0
Valley Gas Company	Direct Energy Marketing Ltd.	1.0
Vermont Gas Systems Inc.	WGML	15.1
Total		430.591

Major New Interconnections:

Location	Company	Capacity	In/Out
Upton, Mass.	Tennessee Gas Pipeline Company	2 MMcf/d	Out
West Medway, Mass.	Algonquin	304.7 MMcf/d	Out
Highgate Springs, VT	TCPL	430.6 MMcf/d	Out

Physical Capacity:

205 MMcf/d - October 31/1991
430.6 MMcf/d - October 31/1992

PROJECT NAME: IROQUOIS

Description: Will carry Canadian gas from TCPL to markets in New York, Connecticut, Massachusetts, New Jersey, Rhode Island, and New Hampshire.

Capital Cost: $523.7 million ($U.S. 1991).

Distance: 307 miles (24" main to Milford, Connecticut, then 20" to Long Island. Total 369 miles - no compression.)

Projected In-service Date: Oct. 31, 1991.

Status of Application: Approved by FERC.

Sponsors/Shares:

TCPL	29%
Brooklyn Union	12%
Northeast Utilities	11%
Southern Connecticut Gas	2.5%
Connecticut Natural Gas	2.5%
New Jersey Natural Resources	2.5%
Tennessee Gas	12.8%
CNG Transmission	6.4%
TETCO	6.4%
ANR	6.4%
AEC Pipelines	6.0%
J. Makowski Company Inc.	2.5%

Tariffs: (1986 $Cdn.)

$.70/Mcf @ 100% Lf.

- will require
  - $267 million in TCPL facilities
  - $ 60 million in NOVA facilities
  - $ 32 million in Union facilities
  - $ 4 million in GLGT facilities

Rates: (Maximum)

	Demand Charge	Depreciation Component	Total Demand	Commodity
Zone 1	$8.5008/MMBtu	.8948	9.3144	13.2619¢/d
Zone 2	16.0020	1.6844	17.5336	24.9645

Shippers/Suppliers/Volumes:

Shippers are natural gas utilities, electric utilities and cogeneration.

Supplier	Max. Volume (MMcf/d)
Alberta Northeast Gas Ltd.*	387.1
WGML	83.4
Atcor	23.0
Altano Exploration	14.4
Metro Gaz	14.0
Shell Canada	12.0
	533.9

*WGML, Progas, Atcor, AEC Oil and Gas.

Major New Interconnections:

Location	Company	Capacity	In/Out
Wright, N.Y.	Tennessee	136.2 MMcf/d	Out
Stratford, Connecticut	Tennessee	75 MMcf/d	Out

Physical Capacity:

534 MMcf/d.

PROJECT NAME: KERN RIVER

Description: Pipeline from Opal, Wyoming, through Utah and Nevada, ending near Bakersfield, California. Primarily to serve EOR, but will also provide gas to the utility market.

Capital Cost: $853 million ($U.S. 1989).

Distance: 901.7 miles (Opal, WY to Kern County, CA).

Projected In-service Date: 1991

Status of Application: Approved by FERC, refiled for optional certificate Sept., 1989.

Sponsors/Shares:

Tenneco	50%
Williams	50%

NOTE: Kern River and Mojave have joined forces, with 64% of the joint venture owned by Kern River.

Tariffs: Projected maximum rate of $0.53-0.59/Mcf dependent upon whether the Investment Tax Credit is available when service commences.

Shippers/Suppliers/Volumes:

Supplier	Max. Volume (MMcf/d)
Chevron	150
Mobil	50
Tenneco	30
Union Pacific Resources	74
Whittier Energy	3
Berry Petroleum	25
City of Long Beach	40
Socal Gas Company	200
City of Burbank	10
Pasedena	10
Glendale	5

Major New Interconnections:

Location	Company	Capacity	In/Out
Bakersfield	Socal	300 MMcf/d	Out

Physical Capacity:

700 MMcf/d.

PROJECT NAME: MACKENZIE VALLEY PIPELINE

Description: A pipeline to follow the Mackenzie River Valley, transporting natural gas to Caroline. An alternative to ANGTS. Has support of the native population.

Capital Cost: $4.4 billion ($1988 Cdn.).

Distance: 2300 km (1400 miles).

Projected In-service Date: Nov. 1, 1996.

Status of Application: No application yet.

Sponsors/Shares:

Foothills

Tariffs: Delivered cost from Mackenzie Delta to Southern Alberta is projected in the $1.60 U.S./Mcf range.

Shippers/Suppliers/Volumes:

Shell	Enron	.9 Tcf
Esso	Texas Eastern	5.1 Tcf
Gulf	Tennessee Gas	3.2 Tcf
	PITCO	

Major New Interconnections:

Location	Company	Capacity
Mackenzie Delta to Boundary Lake	Foothills	1023 miles of 34" line (1.2 Bcf/d)
Boundary Lake to Caroline	Foothills	407 miles of 48" line (1.2 Bcf/d expandable to an additional 2.3 Bcf/d with compression)

Physical Capacity:

1.2 Bcf/d.

PROJECT NAME: MOJAVE

Description: Will take gas from Southwest U.S. to California EOR/Utility market as a joint venture with Kern River.

Capital Cost: $307 million ($U.S. 1988).

Distance: 384 miles.

Projected In-service Date: Early 1992.

Status of Application: Optional Certificate approved by FERC.

Sponsors/Shares:

El Paso	50%
Enron	50%

Tariffs:

- Maximum rate $0.35/Mcf, demand component of $0.197/Mcf

Shippers/Suppliers/Volumes:

Texaco	185 MMcf/d firm, 50MMcf/d interruptible.
OXY U.S.A. Inc.	37.5 MMcf/d firm - option for additional 37.5 MMcf/d.

Major New Interconnections:

Location	Company	Capacity	In/Out
Topock, Arizona	El Paso & Transwestern	600	Out

Physical Capacity:

600 MMcf/d

PROJECT NAME: NORTHERN BORDER EXPANSION

Description: An expansion of existing capacity on the East Leg of the Alaska pipeline prebuild. Only compression required initially, with a staged approach. Phase Two involves extension to Tuscola interconnection with Panhandle and Trunkline.

Capital Cost: $550 million ($Cdn.), Phase I & Phase II.

Distance: Phase II, 371 miles, 36".

Projected In-service Date: November 1, 1990 for first phase.

Status of Application: Under FERC review.

Sponsors/Shares:

Northern Border

Tariffs: Expansion will reduce toll by 20 percent in Saskatchewan.

Phase I, reduce toll from $0.57 to $0.53/Mcf ($U.S.)
Phase II, reduce $0.39/Mcf--excl. fuel--($U.S.)

($Cdn.) 1989.

	Total Capacity	Cdn. Cost	U.S. Cost	Unit Cost
Add 275 MMcf/d	1.35 bcf/d	40	515	.75
Add 475 MMcf/d	1.55 bcf/d	95	640	.70
Add 725 MMcf/d	1.8 bcf/d	140	815	.70

Shippers/Suppliers/Volumes:

Current	Supplier	Volume (MMcf/d)
Northern Natural	Pan Alberta	200
Panhandle	Pan Alberta	150
United (now Pan Alberta)	Pan Alberta	450
Northern Natural	Consolidated	100
NGPL	Progas	75
ANR	Great Plains Project	34
NGPL	Great Plains Project	28
Tenessee	Great Plains Project	41
Transco	Great Plains Project	34
Suncor	Suncor	50
North Canadian Oils	NCO	50
Total		1212

N.B.: Has applied for compressor in South Dakota to add 150 MMcf/d of capacity for TCPL, Salmon Resources. Currently TCPL has 100 MMcf/d. New space would be 120 MMcf/d TCPL, 30 Salmon.

Major New Interconnections:

Location	Company	Capacity	In/Out
Ventura > various (Tuscola)	7 major interstates	400 MMcf/d	out

Physical Capacity:

Add 200 MMcf/d to NB capacity to move Cdn. Gas.

- extend line to Ventura adding 400 MMcf/d capacity.
- eventual capacity 1.8 to 2.0 Bcf/d for full system.

PROJECT NAME: NOVA EXPANSION

Description: Expansion of existing Alberta trunklines.

Capital Cost: 1989 expansion of $42 million in pipeline and $115 million in compression. Total of $3 billion over next 6 years ($Cdn.).

Distance: N/A

Projected In-service Date: Staged.

Status of Application: N/A

Sponsors/Shares: Nova.

Tariffs: .32¢/Mcf by 1995.

Shippers/Suppliers/Volumes:

Various domestic and export projects.

Major New Interconnections: N/A

Physical Capacity:

	1987	1988	1989	1990
Receipt (Bcf/d)	10.7	10.9	12.9	13.5
Delivery (Bcf/d)	9.1	9.2	9.3	10.1

PROJECT NAME: PGT EXPANSION

Description: Expansion of the PGT line to provide firm capacity to Pacific Northwest customers as well as the PGT/PG&E system to provide additional capacity and interconnections to Southern California destinations.

Capital Cost: $1.18 billion - of that $635.1 million for PGT and $544.8 million for PG&E ($U.S. 1988).

Distance: 612 miles PGT, 415 miles PG&E.

Projected In-service Date: November 1, 1993.

Status of Application: N/A

Sponsors/Shares: Southern California Edison and San Diego Gas and Electric have options to acquire up to 25% of project equity. PGT and PG&E will retain at least 75% ownership.

Tariffs:

Kingsgate to Kern River Station	$0.734/Mcf
Kingsgate to Stanfield	$0.175/Mcf
Stanfield to Kern River Station	$0.559/Mcf

ANG rate will rise to about $0.05 (U.S.) per Mcf on a rolled in basis.

California Utilities Volumes:

Southern California Edison	200 MMcf/d
San Diego G&E	100 MMcf/d
City of Long Beach	15 MMcf/d
PG&E	100 MMcf/d
City of Glendale	5 MMcf/d
City of Burbank	5 MMcf/d
City of Pasadena	5 MMcf/d

Third Party Shippers (Kingsgate, B.C. to CA)

Salmon Resources Ltd.	50 MMcf/d
Suncor Inc.	50 MMcf/d
Pancontinental Oil Ltd.	5 MMcf/d
Trigen Resources Corp.	50 MMcf/d
Nat. Gas. Inc. (Pan Alberta Gas Ltd.)	50 MMcf/d
BP Gas Inc.	10 MMcf/d
BP Resources Canada Ltd.*	10 MMcf/d
Williams Gas Marketing Co.*	50 MMcf/d
American Hunter Exploration Ltd.	50 MMcf/d
TOTAL TO CALIFORNIA	755 MMcf/d

*Stanfield, Oregon to California

Into Pacific N.W.:

Washington Water Power	45 MMcf/d
Northwest Natural	40 MMcf/d
IGI Resources	33 MMcf/d
Cascade Natural Gas	30 MMcf/d
	148 MMcf/d

Major New Interconnections: None

Physical Capacity (Annual Average):

755 MMcf/d to California
150 MMcf/d to Pacific N.W.
PG&E will add 755 MMcf/d capacity from Malin to Kern River Station.

PROJECT NAME: TCPL EXPANSION

Description: Staged expansion of the TCPL system to meet export requirements of various proposals as well as increased domestic capacity.

Capital Cost:

Phase	TCPL ($MM Cdn.)	GLGT ($MM U.S.)
1	700	200
2	650	440
3	1,235	950
	2,585	1,590

Distance:

Projected In-service Date:

Phase I - November 1, 1989
Phase II - November 1, 1990
Phase III - November 1, 1991 & 1992

Status of Application: Phase I approved, Phase II approved (except 51 MMcf/d for Niagara Mohawk), Phase III filed.

Sponsors/Shares: TCPL

Tariffs: N/A

Shippers/Suppliers/Volumes: N/A

Major New Interconnections:

Location	Company	Capacity	In/Out
	Iroquois		
	Champlain		
	Empire State		

Physical Capacity:

Iroquois	499 MMcf/d	Phase III
Champlain	321 MMcf/d	Phase III
Domestic	78 MMcf/d	Phase II
Export	459 MMcf/d	Phase II
Domestic	178 MMcf/d	Phase I
Export	258 MMcf/d	Phase I

PROJECT NAME: WYCAL

Description: A line to carry Rocky Mountain gas from Wyoming to California EOR fields.

Capital Cost: $665.5 million ($U.S. 1987).

Distance: 1,000 miles.

Projected In-service Date: Nov. 1, 1991.

Status of Application: Optional Certificate, approved by FERC.

Sponsors/Shares:

Coastal Western Pipeline Company
CIG Western Pipeline Company

- both subs of Colorado Interstate Corporation, which is owned by the Coastal Corporation.

Tariffs: Maximum @ 100% L.F.

	Reservation (Mcf/month)	Commodity ($/Mcf)
Supply Area	1.83	.0147
Anschutz > Bakersfield	17.49	.1569
Topock > Bakersfield	6.73	.0610

i.e., Supply area > Bakersfield @ 100% L.F. is ± $0.81/Mcf max.

Shippers/Suppliers/Volumes:

- PG&E	50 MMcf/d
- Socal	50 MMcf/d (option to take 75 MMcf/d)
- Socal Edison	50 MMcf/d

Major New Interconnections:

Location	Company	Capacity	In/Out
	NWP El Paso Transwestern		

Physical Capacity:

400 MMcf/d	Overthrust > Piute Junction, California
650 MMcf/d	Piute > Bakersfield

APPENDIX B

SELECTED DATA RESULTS

TABLE B.1

LOWER-48 NATURAL GAS PRODUCTION
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	15.45	15.42	14.35	14.21	14.46	14.63
No New Pipelines		15.49	14.37	14.16	14.48	14.77
No PGT Loop		15.51	14.43	14.27	14.52	14.67
No New California		15.51	14.43	14.27	14.52	14.67
No Champlain/Iroquois		15.42	14.35	14.22	14.47	14.63
Conservative Conventional		15.12	13.82	13.45	13.46	13.34
Moderate Infill Drilling		15.56	14.58	14.51	14.84	15.07
Aggressive Infill Drilling		15.84	15.14	15.13	15.54	15.86
Conservative Offshore Gulf Coast		15.25	14.06	13.80	13.87	13.76
Aggressive Offshore Gulf Coast		15.51	14.52	14.47	14.89	15.27
Conservative Coalbed Methane		15.47	14.42	14.28	14.49	14.68
Aggressive Coalbed Methane		15.48	14.45	14.33	14.57	14.78
Conservative Rocky Mountain		15.40	14.28	14.10	14.30	14.43
Aggressive Rocky Mountain		15.45	14.40	14.29	14.56	14.75
Tight Gas		15.52	14.52	14.47	14.81	15.13
Aggressive North American Conventional		15.87	15.20	15.36	16.01	16.60
Aggressive Canadian Conventional		15.44	14.35	14.20	14.43	14.56
No Canadian Frontier		15.45	14.38	14.24	14.51	14.79
Aggressive Canadian Frontier		15.42	14.36	14.22	14.49	14.64

SOURCE: Canadian Energy Research Institute.

TABLE B.2

ALASKA NATURAL GAS PRODUCTION
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	0.19	0.21	0.21	0.22	0.30	1.02
No New Pipelines		0.21	0.21	0.22	0.23	0.24
No PGT Loop		0.21	0.21	0.22	0.28	1.02
No New California		0.21	0.21	0.22	0.29	1.02
No Champlain/Iroquois		0.21	0.21	0.22	0.30	1.02
Conservative Conventional		0.21	0.21	0.22	0.34	1.03
Moderate Infill Drilling		0.21	0.21	0.22	0.31	1.02
Aggressive Infill Drilling		0.21	0.21	0.22	0.27	1.02
Conservative Offshore Gulf Coast		0.21	0.21	0.22	0.32	1.03
Aggressive Offshore Gulf Coast		0.21	0.21	0.22	0.28	1.02
Conservative Coalbed Methane		0.21	0.21	0.22	0.29	1.02
Aggressive Coalbed Methane		0.21	0.21	0.22	0.29	1.02
Conservative Rocky Mountain		0.21	0.21	0.22	0.32	1.03
Aggressive Rocky Mountain		0.21	0.21	0.22	0.29	1.02
Tight Gas		0.21	0.21	0.22	0.28	1.02
Aggressive North American Conventional		0.21	0.21	0.22	0.27	0.65
Aggressive Canadian Conventional		0.21	0.21	0.22	0.24	0.55
No Canadian Frontier		0.21	0.21	0.22	0.63	1.05
Aggressive Canadian Frontier		0.21	0.21	0.22	0.29	1.02

SOURCE: Canadian Energy Research Institute.

TABLE B.3

LNG IMPORTS TO THE UNITED STATES
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	0.04	0.12	0.30	0.40	0.49	0.57
No New Pipelines		0.11	0.30	0.42	0.50	0.59
No PGT Loop		0.11	0.30	0.41	0.49	0.57
No New California		0.12	0.30	0.41	0.49	0.57
No Champlain/Iroquois		0.12	0.30	0.42	0.50	0.57
Conservative Conventional		0.11	0.31	0.42	0.50	0.58
Moderate Infill Drilling		0.11	0.30	0.41	0.49	0.57
Aggressive Infill Drilling		0.11	0.21	0.41	0.48	0.56
Conservative Offshore Gulf Coast		0.11	0.31	0.42	0.50	0.58
Aggressive Offshore Gulf Coast		0.11	0.30	0.41	0.49	0.57
Conservative Coalbed Methane		0.12	0.30	0.41	0.49	0.57
Aggressive Coalbed Methane		0.11	0.30	0.41	0.49	0.57
Conservative Rocky Mountain		0.11	0.30	0.41	0.49	0.57
Aggressive Rocky Mountain		0.11	0.30	0.41	0.49	0.57
Tight Gas		0.11	0.30	0.41	0.49	0.56
Aggressive North American Conventional		0.11	0.21	0.38	0.46	0.54
Aggressive Canadian Conventional		0.11	0.30	0.41	0.48	0.57
No Canadian Frontier		0.11	0.30	0.42	0.50	0.57
Aggressive Canadian Frontier		0.11	0.30	0.41	0.49	0.57

SOURCE: Canadian Energy Research Institute.

TABLE B.4

CANADIAN NATURAL GAS EXPORTS TO THE UNITED STATES
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	0.93	1.93	1.94	1.97	1.94	1.23
No New Pipelines		1.69	1.60	1.56	1.42	1.15
No PGT Loop		1.82	1.85	1.89	1.89	1.19
No New California		1.81	1.84	1.88	1.88	1.18
No Champlain/Iroquois		1.91	1.93	1.95	1.92	1.20
Conservative Conventional		1.97	2.01	2.05	2.01	1.37
Moderate Infill Drilling		1.91	1.92	1.94	1.88	1.16
Aggressive Infill Drilling		1.87	1.87	1.89	1.87	1.12
Conservative Offshore Gulf Coast		1.95	1.97	2.00	1.97	1.31
Aggressive Offshore Gulf Coast		1.92	1.94	1.95	1.93	1.17
Conservative Coalbed Methane		1.92	1.94	1.95	1.93	1.20
Aggressive Coalbed Methane		1.92	1.94	1.95	1.93	1.20
Conservative Rocky Mountain		1.91	1.96	2.01	1.99	1.29
Aggressive Rocky Mountain		1.92	1.94	1.96	1.95	1.22
Tight Gas		1.92	1.94	1.96	1.94	1.20
Aggressive North American Conventional		1.92	2.01	2.09	2.11	1.78
Aggressive Canadian Conventional		1.96	2.09	2.24	2.37	2.20
No Canadian Frontier		1.86	1.84	1.85	1.46	0.86
Aggressive Canadian Frontier		1.94	1.96	1.99	1.96	1.25

SOURCE: Canadian Energy Research Institute.

TABLE B.5

AVERAGE UNITED STATES WELLHEAD PRICES
($1987 U.S./Mcf)

Case	1987	1992	1997	2002	2007	2012
Reference Case	1.80	2.30	2.90	3.60	4.40	5.30
No New Pipelines		2.35	2.95	3.70	4.50	5.45
No PGT Loop		2.30	2.90	3.60	4.40	5.35
No New California		2.30	2.90	3.60	4.40	5.30
No Champlain/Iroquois		2.30	2.90	3.60	4.40	5.30
Conservative Conventional		2.40	3.05	3.85	4.80	5.85
Moderate Infill Drilling		2.25	2.80	3.50	4.25	5.15
Aggressive Infill Drilling		2.15	2.70	3.35	4.05	4.85
Conservative Offshore Gulf Coast		2.35	3.00	3.75	4.60	5.65
Aggressive Offshore Gulf Coast		2.30	2.85	3.55	4.25	5.10
Conservative Coalbed Methane		2.30	2.85	3.55	4.35	5.20
Aggressive Coalbed Methane		2.30	2.85	3.55	4.30	5.15
Conservative Rocky Mountain		2.35	2.95	3.70	4.55	5.50
Aggressive Rocky Mountain		2.30	2.85	3.60	4.35	5.25
Tight Gas		2.25	2.80	3.50	4.20	5.00
Aggressive North American Conventional		2.10	2.55	3.10	3.65	4.25
Aggressive Canadian Conventional		2.30	2.85	3.60	4.35	5.25
No Canadian Frontier		2.35	2.90	3.65	4.45	5.40
Aggressive Canadian Frontier		2.30	2.90	3.60	4.40	5.30

SOURCE: Canadian Energy Research Institute.

TABLE B.6

ROCKY MOUNTAIN REGION NATURAL GAS PRODUCTION
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	0.73	1.11	1.35	1.55	1.65	1.72
No New Pipelines		1.09	1.22	1.33	1.40	1.46
No PGT Loop		1.11	1.38	1.56	1.66	1.72
No New California		1.11	1.38	1.56	1.66	1.72
No Champlain/Iroquois		1.11	1.35	1.55	1.65	1.72
Conservative Conventional		1.10	1.31	1.51	1.59	1.66
Moderate Infill Drilling		1.12	1.37	1.57	1.67	1.74
Aggressive Infill Drilling		1.13	1.40	1.60	1.70	1.77
Conservative Offshore Gulf Coast		1.12	1.37	1.57	1.67	1.74
Aggressive Offshore Gulf Coast		1.11	1.35	1.55	1.65	1.71
Conservative Coalbed Methane		1.11	1.35	1.55	1.64	1.70
Aggressive Coalbed Methane		1.11	1.35	1.55	1.64	1.70
Conservative Rocky Mountain		1.02	1.24	1.41	1.44	1.45
Aggressive Rocky Mountain		1.13	1.38	1.59	1.70	1.77
Tight Gas		1.12	1.37	1.57	1.67	1.75
Aggressive North American Conventional		1.11	1.35	1.54	1.63	1.69
Aggressive Canadian Conventional		1.12	1.36	1.54	1.62	1.68
No Canadian Frontier		1.11	1.36	1.56	1.66	1.73
Aggressive Canadian Frontier		1.11	1.35	1.55	1.66	1.72

SOURCE: Canadian Energy Research Institute.

TABLE B.7

ROCKY MOUNTAIN REGION NATURAL GAS WELLHEAD PRICES ($1987 U.S./Mcf)

Case	1987	1992	1997	2002	2007	2012
Reference Case	1.40	1.75	2.10	2.65	3.20	3.85
No New Pipelines		1.62	1.95	2.39	2.90	3.51
No PGT Loop		1.75	2.10	2.65	3.20	3.85
No New California		1.75	2.10	2.65	3.20	3.85
No Champlain/Iroquois		1.75	2.10	2.65	3.20	3.85
Conservative Conventional		1.90	2.30	2.95	3.70	4.50
Moderate Infill Drilling		1.65	2.00	2.50	3.00	3.60
Aggressive Infill Drilling		1.55	1.85	2.20	2.70	3.20
Conservative Offshore Gulf Coast		1.75	2.15	2.70	3.30	3.95
Aggressive Offshore Gulf Coast		1.70	2.10	2.60	3.15	3.75
Conservative Coalbed Methane		1.70	2.10	2.60	3.15	3.80
Aggressive Coalbed Methane		1.70	2.05	2.60	3.10	3.70
Conservative Rocky Mountain		1.90	2.40	3.05	3.90	4.80
Aggressive Rocky Mountain		1.65	2.00	2.50	2.95	3.50
Tight Gas		1.65	2.00	2.50	3.00	3.50
Aggressive North American Conventional		1.55	1.85	2.25	2.60	3.00
Aggressive Canadian Conventional		1.70	2.10	2.60	3.15	3.75
No Canadian Frontier		1.75	2.15	2.70	3.25	3.90
Aggressive Canadian Frontier		1.75	2.10	2.65	3.20	3.85

SOURCE: Canadian Energy Research Institute.

TABLE B.8

UNITED STATES NATURAL GAS DEMAND
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	16.45	17.75	16.93	16.92	17.25	17.45
No New Pipelines		17.60	16.66	16.53	16.76	16.89
No PGT Loop		17.72	16.90	16.89	17.22	17.44
No New California		17.72	16.90	16.88	17.21	17.43
No Champlain/Iroquois		17.76	16.94	16.93	17.25	17.46
Conservative Conventional		17.48	16.47	16.23	16.33	16.28
Moderate Infill Drilling		17.87	17.16	17.24	17.64	17.91
Aggressive Infill Drilling		18.12	17.60	17.82	18.33	18.68
Conservative Offshore Gulf Coast		17.60	16.68	16.55	16.73	16.71
Aggressive Offshore Gulf Coast		17.84	17.10	17.18	17.64	18.03
Conservative Coalbed Methane		17.80	17.02	17.05	17.43	17.70
Aggressive Coalbed Methane		17.82	17.06	17.11	17.51	17.79
Conservative Rocky Mountain		17.72	16.88	16.85	17.15	17.33
Aggressive Rocky Mountain		17.78	16.98	16.99	17.34	17.57
Tight Gas		17.84	17.10	17.16	17.58	17.91
Aggressive North American Conventional		18.19	17.77	18.19	18.97	19.65
Aggressive Canadian Conventional		17.81	17.04	17.09	17.48	17.78
No Canadian Frontier		17.72	16.88	16.85	17.15	17.31
Aggressive Canadian Frontier		17.76	16.95	16.95	17.28	17.49

SOURCE: Canadian Energy Research Institute.

TABLE B.9

AVERAGE CALIFORNIA BURNER-TIP NATURAL GAS PRICES
($1987 U.S./Mcf in core markets)

Case	1987	1992	1997	2002	2007	2012
Reference Case	4.60	5.45	6.30	7.30	8.50	9.80
No New Pipelines		5.75	6.70	7.90	9.20	10.60
No PGT Loop		5.65	6.45	7.50	8.70	9.95
No New California		5.65	6.45	7.55	8.70	9.95
No Champlain/Iroquois		5.45	6.30	7.30	8.50	9.80
Conservative Conventional		5.65	6.55	7.70	9.00	10.45
Moderate Infill Drilling		5.40	6.20	7.15	8.30	9.55
Aggressive Infill Drilling		5.25	6.00	6.95	8.00	9.15
Conservative Offshore Gulf Coast		5.50	6.40	7.40	8.65	10.00
Aggressive Offshore Gulf Coast		5.45	6.30	7.30	8.45	9.70
Conservative Coalbed Methane		5.45	6.30	7.25	8.40	9.65
Aggressive Coalbed Methane		5.45	6.30	7.25	8.35	9.65
Conservative Rocky Mountain		5.50	6.35	7.35	8.60	9.90
Aggressive Rocky Mountain		5.45	6.30	7.30	8.50	9.80
Tight Gas		5.45	6.25	7.25	8.45	9.70
Aggressive North American Conventional		5.20	5.95	6.80	7.75	8.75
Aggressive Canadian Conventional		5.45	6.30	7.30	8.45	9.70
No Canadian Frontier		5.50	6.35	7.40	8.60	10.00
Aggressive Canadian Frontier		5.45	6.30	7.35	8.55	9.85

SOURCE: Canadian Energy Research Institute.

TABLE B.10

AVERAGE PACIFIC NORTHWEST BURNER-TIP NATURAL GAS PRICES
($1987 U.S./Mcf in core markets)

Case	1987	1992	1997	2002	2007	2012
Reference Case	4.60	4.95	5.40	5.95	6.65	7.80
No New Pipelines		5.05	5.60	6.20	7.03	8.35
No PGT Loop		4.95	5.40	5.95	6.65	7.80
No New California		4.95	5.40	5.90	6.65	7.75
No Champlain/Iroquois		4.95	5.40	5.95	6.65	7.80
Conservative Conventional		5.05	5.50	6.05	6.80	8.05
Moderate Infill Drilling		4.95	5.35	5.90	6.60	7.70
Aggressive Infill Drilling		4.90	5.35	5.85	6.50	7.60
Conservative Offshore Gulf Coast		5.00	5.45	6.00	6.70	7.90
Aggressive Offshore Gulf Coast		4.95	5.40	5.90	6.60	7.75
Conservative Coalbed Methane		4.95	5.40	5.90	6.65	7.75
Aggressive Coalbed Methane		4.95	5.40	5.90	6.60	7.75
Conservative Rocky Mountain		5.00	5.45	6.00	6.75	7.95
Aggressive Rocky Mountain		4.95	5.40	5.95	6.65	7.80
Tight Gas		4.95	5.40	5.90	6.60	7.75
Aggressive North American Conventional		4.75	5.00	5.35	5.75	6.45
Aggressive Canadian Conventional		4.85	5.15	5.50	6.00	6.85
No Canadian Frontier		5.00	5.55	6.10	6.90	8.20
Aggressive Canadian Frontier		4.95	5.40	5.90	6.65	7.80

SOURCE: Canadian Energy Research Institute.

TABLE B.11

AVERAGE WNC/MOUNTAIN BURNER-TIP NATURAL GAS PRICES
($1987 U.S./Mcf in core markets)

Case	1987	1992	1997	2002	2007	2012
Reference Case	4.70	5.15	5.75	6.60	7.50	8.50
No New Pipelines		5.20	5.80	6.70	7.60	8.70
No PGT Loop		5.15	5.80	6.65	7.55	8.55
No New California		5.15	5.75	6.65	7.55	8.55
No Champlain/Iroquois		5.15	5.75	6.60	7.55	8.55
Conservative Conventional		5.25	5.90	6.85	7.85	9.00
Moderate Infill Drilling		5.10	5.70	6.50	7.40	8.35
Aggressive Infill Drilling		5.00	5.55	6.35	7.20	8.10
Conservative Offshore Gulf Coast		5.20	5.85	6.75	7.70	8.80
Aggressive Offshore Gulf Coast		5.10	5.75	6.55	7.40	8.35
Conservative Coalbed Methane		5.10	5.75	6.55	7.40	8.40
Aggressive Coalbed Methane		5.10	5.75	6.55	7.40	8.35
Conservative Rocky Mountain		5.20	5.80	6.70	7.65	8.70
Aggressive Rocky Mountain		5.15	5.75	6.60	7.50	8.50
Tight Gas		5.10	5.70	6.50	7.40	8.30
Aggressive North American Conventional		4.95	5.45	6.10	6.75	7.40
Aggressive Canadian Conventional		5.15	5.75	6.60	7.50	8.50
No Canadian Frontier		5.15	5.80	6.65	7.60	8.65
Aggressive Canadian Frontier		5.15	5.75	6.60	7.55	8.55

SOURCE: Canadian Energy Research Institute.

TABLE B.12

AVERAGE NEW ENGLAND BURNER-TIP NATURAL GAS PRICES
($1987 U.S./Mcf in core markets)

Case	1987	1992	1997	2002	2007	2012
Reference Case	6.10	6.70	7.40	8.30	9.20	10.40
No New Pipelines		6.75	7.50	8.40	9.35	10.55
No PGT Loop		6.70	7.40	8.30	9.20	10.40
No New California		6.75	7.45	8.30	9.25	10.45
No Champlain/Iroquois		6.70	7.40	8.30	9.25	10.35
Conservative Conventional		6.85	7.60	8.55	9.55	10.95
Moderate Infill Drilling		6.65	7.35	8.20	9.10	10.25
Aggressive Infill Drilling		6.60	7.20	8.05	8.90	9.95
Conservative Offshore Gulf Coast		6.80	7.55	8.45	9.45	10.80
Aggressive Offshore Gulf Coast		6.70	7.40	8.25	9.10	10.15
Conservative Coalbed Methane		6.70	7.40	8.35	9.15	10.30
Aggressive Coalbed Methane		6.70	7.40	8.25	9.15	10.25
Conservative Rocky Mountain		6.75	7.45	8.35	9.30	10.50
Aggressive Rocky Mountain		6.70	7.40	8.30	9.20	10.40
Tight Gas		6.65	7.35	8.20	9.05	10.05
Aggressive North American Conventional		6.50	7.05	7.70	8.35	9.10
Aggressive Canadian Conventional		6.70	7.40	8.10	8.85	9.80
No Canadian Frontier		6.75	7.45	8.35	9.30	10.55
Aggressive Canadian Frontier		6.75	7.45	8.30	9.25	10.40

SOURCE: Canadian Energy Research Institute.

TABLE B.13

BRITISH COLUMBIA NATURAL GAS PRODUCTION
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	0.31	0.54	0.59	0.63	0.68	0.69
No New Pipelines		0.54	0.59	0.62	0.68	0.70
No PGT Loop		0.54	0.59	0.62	0.68	0.69
No New California		0.54	0.59	0.62	0.67	0.69
No Champlain/Iroquois		0.54	0.59	0.63	0.68	0.69
Conservative Conventional		0.55	0.60	0.64	0.69	0.71
Moderate Infill Drilling		0.54	0.59	0.62	0.67	0.69
Aggressive Infill Drilling		0.54	0.59	0.62	0.67	0.68
Conservative Offshore Gulf Coast		0.54	0.59	0.63	0.68	0.70
Aggressive Offshore Gulf Coast		0.54	0.59	0.63	0.68	0.69
Conservative Coalbed Methane		0.54	0.59	0.63	0.68	0.69
Aggressive Coalbed Methane		0.54	0.59	0.63	0.68	0.69
Conservative Rocky Mountain		0.54	0.59	0.63	0.70	0.71
Aggressive Rocky Mountain		0.54	0.59	0.63	0.68	0.69
Tight Gas		0.54	0.59	0.63	0.68	0.69
Aggressive North American Conventional		0.56	0.63	0.69	0.77	0.84
Aggressive Canadian Conventional		0.55	0.63	0.69	0.78	0.83
No Canadian Frontier		0.54	0.60	0.62	0.67	0.70
Aggressive Canadian Frontier		0.54	0.59	0.62	0.68	0.69

SOURCE: Canadian Energy Research Institute.

TABLE B.14

ALBERTA NATURAL GAS PRODUCTION
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	2.45	3.34	3.39	3.53	3.52	3.00
No New Pipelines		3.16	3.04	3.16	3.22	3.10
No PGT Loop		3.25	3.30	3.47	3.48	2.97
No New California		3.24	3.29	3.47	3.47	2.97
No Champlain/Iroquois		3.34	3.39	3.53	3.52	3.00
Conservative Conventional		3.35	3.40	3.51	3.50	3.03
Moderate Infill Drilling		3.34	3.38	3.51	3.49	2.97
Aggressive Infill Drilling		3.31	3.35	3.52	3.54	2.99
Conservative Offshore Gulf Coast		3.34	3.40	3.52	3.51	3.02
Aggressive Offshore Gulf Coast		3.33	3.39	3.54	3.54	2.99
Conservative Coalbed Methane		3.34	3.39	3.53	3.52	3.00
Aggressive Coalbed Methane		3.33	3.39	3.53	3.53	3.00
Conservative Rocky Mountain		3.33	3.40	3.53	3.54	3.03
Aggressive Rocky Mountain		3.33	3.39	3.53	3.53	3.01
Tight Gas		3.33	3.39	3.54	3.54	3.01
Aggressive North American Conventional		3.32	3.42	3.70	3.92	3.80
Aggressive Canadian Conventional		3.32	3.42	3.70	4.00	3.85
No Canadian Frontier		3.28	3.27	3.46	3.31	2.87
Aggressive Canadian Frontier		3.35	3.40	3.37	3.53	3.02

SOURCE: Canadian Energy Research Institute.

TABLE B.15

SASKATCHEWAN NATURAL GAS PRODUCTION
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	0.11	0.51	0.48	0.37	0.27	0.20
No New Pipelines		0.44	0.45	0.35	0.26	0.18
No PGT Loop		0.50	0.48	0.36	0.27	0.19
No New California		0.50	0.48	0.36	0.27	0.20
No Champlain/Iroquois		0.51	0.48	0.37	0.27	0.20
Conservative Conventional		0.51	0.48	0.36	0.27	0.20
Moderate Infill Drilling		0.50	0.48	0.36	0.27	0.20
Aggressive Infill Drilling		0.51	0.48	0.36	0.27	0.19
Conservative Offshore Gulf Coast		0.51	0.48	0.36	0.27	0.20
Aggressive Offshore Gulf Coast		0.52	0.49	0.37	0.27	0.19
Conservative Coalbed Methane		0.51	0.48	0.37	0.27	0.20
Aggressive Coalbed Methane		0.51	0.49	0.37	0.27	0.20
Conservative Rocky Mountain		0.51	0.48	0.37	0.27	0.20
Aggressive Rocky Mountain		0.52	0.49	0.37	0.27	0.20
Tight Gas		0.52	0.49	0.37	0.27	0.19
Aggressive North American Conventional		0.55	0.57	0.45	0.35	0.26
Aggressive Canadian Conventional		0.58	0.57	0.44	0.35	0.27
No Canadian Frontier		0.49	0.48	0.36	0.27	0.20
Aggressive Canadian Frontier		0.51	0.48	0.36	0.27	0.20

SOURCE: Canadian Energy Research Institute.

TABLE B.16

NORTHERN CANADA NATURAL GAS PRODUCTION
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	0.00	0.00	0.01	0.09	0.32	0.34
No New Pipelines			0.00	0.00	0.00	0.00
No PGT Loop			0.00	0.08	0.32	0.34
No New California			0.01	0.08	0.32	0.34
No Champlain/Iroquois			0.01	0.09	0.32	0.34
Conservative Conventional			0.02	0.13	0.33	0.35
Moderate Infill Drilling			0.01	0.10	0.32	0.34
Aggressive Infill Drilling			0.01	0.07	0.30	0.34
Conservative Offshore Gulf Coast			0.01	0.11	0.32	0.34
Aggressive Offshore Gulf Coast			0.01	0.09	0.32	0.34
Conservative Coalbed Methane			0.01	0.09	0.32	0.34
Aggressive Coalbed Methane			0.01	0.09	0.32	0.34
Conservative Rocky Mountain			0.01	0.12	0.33	0.34
Aggressive Rocky Mountain			0.01	0.09	0.32	0.34
Tight Gas			0.01	0.09	0.32	0.34
Aggressive North American Conventional			0.01	0.05	0.17	0.22
Aggressive Canadian Conventional			0.03	0.08	0.15	0.31
No Canadian Frontier			0.00	0.00	0.00	0.00
Aggressive Canadian Frontier			0.03	0.31	0.34	0.36

SOURCE: Canadian Energy Research Institute.

TABLE B.17

TOTAL CANADIAN NATURAL GAS PRODUCTION
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	2.87	4.39	4.48	4.61	4.84	4.29
No New Pipelines		4.14	4.09	4.14	4.19	4.01
No PGT Loop		4.29	4.38	4.53	4.80	4.26
No New California		4.28	4.37	4.53	4.79	4.25
No Champlain/Iroquois		4.39	4.48	4.61	4.84	4.29
Conservative Conventional		4.42	4.50	4.64	4.84	4.34
Moderate Infill Drilling		4.38	4.46	4.60	4.81	4.25
Aggressive Infill Drilling		4.36	4.43	4.58	4.84	4.26
Conservative Offshore Gulf Coast		4.40	4.48	4.62	4.84	4.32
Aggressive Offshore Gulf Coast		4.39	4.48	4.61	4.86	4.27
Conservative Coalbed Methane		4.39	4.48	4.61	4.84	4.28
Aggressive Coalbed Methane		4.39	4.48	4.61	4.85	4.29
Conservative Rocky Mountain		4.37	4.49	4.64	4.88	4.34
Aggressive Rocky Mountain		4.39	4.48	4.61	4.85	4.29
Tight Gas		4.39	4.48	4.61	4.86	4.29
Aggressive North American Conventional		4.42	4.63	4.88	5.24	5.17
Aggressive Canadian Conventional		4.45	4.65	4.90	5.30	5.31
No Canadian Frontier		4.31	4.34	4.45	4.28	3.80
Aggressive Canadian Frontier		4.40	4.50	4.65	4.87	4.33

SOURCE: Canadian Energy Research Institute.

TABLE B.18

AVERAGE BRITISH COLUMBIA WELLHEAD NATURAL GAS PRICES
($1987 U.S./Mcf)

Case	1987	1992	1997	2002	2007	2012
Reference Case	1.15	1.50	2.00	2.50	3.20	4.40
No New Pipelines		1.65	2.15	2.70	3.55	4.85
No PGT Loop		1.50	2.00	2.50	3.20	4.30
No New California		1.50	1.95	2.45	3.15	4.30
No Champlain/Iroquois		1.50	2.00	2.50	3.20	4.35
Conservative Conventional		1.60	2.05	2.60	3.35	4.60
Moderate Infill Drilling		1.50	1.95	2.45	3.15	4.30
Aggressive Infill Drilling		1.50	1.90	2.40	3.10	4.15
Conservative Offshore Gulf Coast		1.55	2.00	2.55	3.25	4.45
Aggressive Offshore Gulf Coast		1.50	1.95	2.45	3.15	4.30
Conservative Coalbed Methane		1.50	1.95	2.50	3.20	4.35
Aggressive Coalbed Methane		1.50	1.95	2.45	3.20	4.30
Conservative Rocky Mountain		1.55	2.00	2.55	3.30	4.50
Aggressive Rocky Mountain		1.55	2.00	2.50	3.20	4.35
Tight Gas		1.50	1.95	2.45	3.15	4.30
Aggressive North American Conventional		1.35	1.60	1.90	2.35	3.05
Aggressive Canadian Conventional		1.40	1.70	2.05	2.60	3.30
No Canadian Frontier		1.60	2.10	2.65	3.45	4.70
Aggressive Canadian Frontier		1.50	1.95	2.50	3.20	4.35

SOURCE: Canadian Energy Research Institute.

TABLE B.19

AVERAGE ALBERTA WELLHEAD NATURAL GAS PRICES
($1987 U.S./Mcf)

Case	1987	1992	1997	2002	2007	2012
Reference Case	1.30	1.70	2.30	2.90	3.70	4.80
No New Pipelines		1.90	2.60	3.40	4.50	6.00
No PGT Loop		1.65	2.25	2.85	3.65	4.70
No New California		1.65	2.25	2.85	3.65	4.70
No Champlain/Iroquois		1.70	2.30	2.90	3.70	4.80
Conservative Conventional		1.75	2.35	3.00	3.85	5.00
Moderate Infill Drilling		1.65	2.25	2.85	3.65	4.70
Aggressive Infill Drilling		1.65	2.20	2.85	3.55	4.60
Conservative Offshore Gulf Coast		1.70	2.30	3.00	3.75	4.90
Aggressive Offshore Gulf Coast		1.65	2.25	2.90	3.65	4.70
Conservative Coalbed Methane		1.65	2.25	2.90	3.65	4.75
Aggressive Coalbed Methane		1.65	2.25	2.90	3.65	4.70
Conservative Rocky Mountain		1.70	2.30	3.00	3.75	4.90
Aggressive Rocky Mountain		1.70	2.30	2.90	3.70	4.80
Tight Gas		1.65	2.25	2.90	3.60	4.65
Aggressive North American Conventional		1.50	1.90	2.30	2.90	3.55
Aggressive Canadian Conventional		1.60	2.00	2.45	3.10	3.85
No Canadian Frontier		1.80	2.50	3.20	4.15	5.45
Aggressive Canadian Frontier		1.65	2.25	2.85	3.65	4.75

SOURCE: Canadian Energy Research Institute.

TABLE B.20

AVERAGE SASKATCHEWAN WELLHEAD NATURAL GAS PRICES
($1987 U.S./Mcf)

Case	1987	1992	1997	2002	2007	2012
Reference Case	1.50	1.90	2.65	3.45	4.45	5.70
No New Pipelines		2.15	3.00	3.95	5.20	7.10
No PGT Loop		1.90	2.60	3.40	4.35	5.65
No New California		1.90	2.60	3.40	4.35	5.65
No Champlain/Iroquois		1.90	2.65	3.45	4.45	5.75
Conservative Conventional		1.95	2.70	3.55	4.60	6.00
Moderate Infill Drilling		1.90	2.60	3.40	4.40	5.70
Aggressive Infill Drilling		1.85	2.55	3.35	4.30	5.50
Conservative Offshore Gulf Coast		1.95	2.70	3.50	4.50	5.85
Aggressive Offshore Gulf Coast		1.90	2.60	3.45	4.40	5.65
Conservative Coalbed Methane		1.90	2.65	3.45	4.40	5.70
Aggressive Coalbed Methane		1.90	2.60	3.45	4.40	5.65
Conservative Rocky Mountain		1.95	2.70	3.55	4.55	5.85
Aggressive Rocky Mountain		1.90	2.65	3.45	4.45	5.70
Tight Gas		1.90	2.60	3.40	4.35	5.60
Aggressive North American Conventional		1.75	2.20	2.80	3.45	4.25
Aggressive Canadian Conventional		1.80	2.30	2.95	3.70	4.65
No Canadian Frontier		2.05	2.90	3.80	5.00	6.40
Aggressive Canadian Frontier		1.90	2.60	3.45	4.40	5.70

SOURCE: Canadian Energy Research Institute.

TABLE B.21

TOTAL CANADIAN NATURAL GAS DEMAND
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	1.82	2.30	2.38	2.50	2.73	2.89
No New Pipelines		2.27	2.31	2.40	2.59	2.69
No PGT Loop		2.31	2.39	2.51	2.75	2.91
No New California		2.31	2.39	2.51	2.75	2.91
No Champlain/Iroquois		2.30	2.38	2.49	2.73	2.89
Conservative Conventional		2.30	2.36	2.47	2.70	2.85
Moderate Infill Drilling		2.31	2.39	2.51	2.75	2.92
Aggressive Infill Drilling		2.31	2.40	2.52	2.77	2.94
Conservative Offshore Gulf Coast		2.30	2.37	2.49	2.72	2.87
Aggressive Offshore Gulf Coast		2.31	2.39	2.50	2.75	2.91
Conservative Coalbed Methane		2.31	2.38	2.50	2.74	2.91
Aggressive Coalbed Methane		2.31	2.38	2.50	2.75	2.91
Conservative Rocky Mountain		2.30	2.37	2.48	2.72	2.87
Aggressive Rocky Mountain		2.31	2.38	2.50	2.74	2.90
Tight Gas		2.31	2.39	2.51	2.75	2.92
Aggressive North American Conventional		2.34	2.46	2.65	2.96	3.21
Aggressive Canadian Conventional		2.32	2.44	2.60	2.90	3.12
No Canadian Frontier		2.28	2.34	2.43	2.64	2.77
Aggressive Canadian Frontier		2.31	2.39	2.51	2.75	2.91

SOURCE: Canadian Energy Research Institute.

TABLE B.22

AVERAGE ONTARIO BURNER-TIP NATURAL GAS PRICES
($1987 U.S./Mcf in core markets)

Case	1987	1992	1997	2002	2007	2012
Reference Case	3.70	4.15	4.80	5.55	6.40	7.60
No New Pipelines		4.35	5.20	6.05	7.30	9.00
No PGT Loop		4.10	4.80	5.50	6.35	7.55
No New California		4.10	4.80	5.50	6.35	7.55
No Champlain/Iroquois		4.15	4.80	5.55	6.40	7.60
Conservative Conventional		4.20	4.90	5.65	6.60	7.90
Moderate Infill Drilling		4.10	4.80	5.50	6.35	7.50
Aggressive Infill Drilling		4.05	4.75	5.45	6.25	7.40
Conservative Offshore Gulf Coast		4.15	4.85	5.60	6.50	7.75
Aggressive Offshore Gulf Coast		4.10	4.80	5.50	6.35	7.50
Conservative Coalbed Methane		4.10	4.80	5.50	6.40	7.60
Aggressive Coalbed Methane		4.10	4.80	5.50	6.35	7.55
Conservative Rocky Mountain		4.15	4.85	5.60	6.50	7.75
Aggressive Rocky Mountain		4.10	4.80	5.55	6.40	7.60
Tight Gas		4.10	4.80	5.50	6.35	7.50
Aggressive North American Conventional		3.95	4.40	4.90	5.50	6.20
Aggressive Canadian Conventional		3.80	4.30	4.80	5.50	6.35
No Canadian Frontier		4.25	5.05	5.80	6.90	8.35
Aggressive Canadian Frontier		4.10	4.80	5.50	6.40	7.55

SOURCE: Canadian Energy Research Institute.

TABLE B.23

CANADIAN NATURAL GAS EXPORTS TO THE PACIFIC NORTHWEST
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	0.13	0.20	0.22	0.22	0.25	0.27
No New Pipelines		0.20	0.20	0.20	0.22	0.23
No PGT Loop		0.21	0.22	0.22	0.25	0.27
No New California		0.21	0.22	0.22	0.25	0.27
No Champlain/Iroquois		0.21	0.22	0.22	0.25	0.27
Conservative Conventional		0.22	0.24	0.24	0.27	0.30
Moderate Infill Drilling		0.20	0.22	0.22	0.25	0.26
Aggressive Infill Drilling		0.20	0.21	0.21	0.24	0.25
Conservative Offshore Gulf Coast		0.20	0.22	0.21	0.25	0.26
Aggressive Offshore Gulf Coast		0.21	0.22	0.22	0.25	0.27
Conservative Coalbed Methane		0.21	0.22	0.22	0.25	0.26
Aggressive Coalbed Methane		0.21	0.22	0.22	0.25	0.27
Conservative Rocky Mountain		0.21	0.22	0.21	0.24	0.26
Aggressive Rocky Mountain		0.21	0.22	0.22	0.25	0.27
Tight Gas		0.21	0.22	0.22	0.25	0.27
Aggressive North American Conventional		0.21	0.24	0.25	0.30	0.34
Aggressive Canadian Conventional		0.20	0.24	0.25	0.29	0.34
No Canadian Frontier		0.20	0.21	0.21	0.24	0.25
Aggressive Canadian Frontier		0.21	0.22	0.22	0.25	0.27

SOURCE: Canadian Energy Research Institute.

TABLE B.24

CANADIAN NATURAL GAS EXPORTS TO CALIFORNIA
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	0.46	0.73	0.71	0.70	0.68	0.65
No New Pipelines		0.50	0.50	0.50	0.50	0.49
No PGT Loop		0.61	0.60	0.59	0.59	0.56
No New California		0.61	0.59	0.58	0.58	0.56
No Champlain/Iroquois		0.73	0.71	0.70	0.68	0.64
Conservative Conventional		0.73	0.71	0.70	0.69	0.65
Moderate Infill Drilling		0.72	0.70	0.70	0.68	0.65
Aggressive Infill Drilling		0.71	0.69	0.69	0.67	0.64
Conservative Offshore Gulf Coast		0.73	0.71	0.70	0.68	0.65
Aggressive Offshore Gulf Coast		0.73	0.71	0.70	0.68	0.65
Conservative Coalbed Methane		0.73	0.71	0.69	0.67	0.64
Aggressive Coalbed Methane		0.73	0.71	0.69	0.67	0.64
Conservative Rocky Mountain		0.72	0.71	0.71	0.72	0.72
Aggressive Rocky Mountain		0.73	0.71	0.70	0.68	0.64
Tight Gas		0.73	0.71	0.70	0.68	0.65
Aggressive North American Conventional		0.73	0.73	0.73	0.72	0.71
Aggressive Canadian Conventional		0.74	0.74	0.75	0.75	0.74
No Canadian Frontier		0.71	0.68	0.67	0.64	0.59
Aggressive Canadian Frontier		0.73	0.71	0.70	0.68	0.65

SOURCE: Canadian Energy Research Institute.

TABLE B.25

CANADIAN NATURAL GAS EXPORTS TO WEST NORTH CENTRAL/MOUNTAIN
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	0.10	0.16	0.16	0.17	0.17	0.17
No New Pipelines		0.16	0.16	0.16	0.16	0.12
No PGT Loop		0.16	0.16	0.17	0.17	0.17
No New California		0.16	0.16	0.17	0.17	0.17
No Champlain/Iroquois		0.16	0.16	0.17	0.17	0.17
Conservative Conventional		0.16	0.17	0.17	0.18	0.18
Moderate Infill Drilling		0.16	0.16	0.17	0.17	0.17
Aggressive Infill Drilling		0.16	0.16	0.17	0.17	0.17
Conservative Offshore Gulf Coast		0.16	0.17	0.17	0.18	0.17
Aggressive Offshore Gulf Coast		0.16	0.16	0.17	0.17	0.17
Conservative Coalbed Methane		0.16	0.16	0.17	0.17	0.17
Aggressive Coalbed Methane		0.16	0.16	0.17	0.17	0.17
Conservative Rocky Mountain		0.16	0.16	0.17	0.17	0.17
Aggressive Rocky Mountain		0.16	0.16	0.17	0.17	0.17
Tight Gas		0.16	0.16	0.17	0.17	0.17
Aggressive North American Conventional		0.16	0.17	0.17	0.17	0.17
Aggressive Canadian Conventional		0.16	0.17	0.18	0.18	0.19
No Canadian Frontier		0.16	0.16	0.16	0.16	0.16
Aggressive Canadian Frontier		0.16	0.16	0.17	0.17	0.17

SOURCE: Canadian Energy Research Institute.

TABLE B.26

CANADIAN NATURAL GAS EXPORTS/ TO EAST NORTH CENTRAL
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	0.17	0.62	0.63	0.64	0.65	0.64
No New Pipelines		0.30	0.30	0.30	0.30	0.30
No PGT Loop		0.63	0.64	0.65	0.66	0.65
No New California		0.63	0.64	0.65	0.66	0.65
No Champlain/Iroquois		0.63	0.63	0.64	0.65	0.64
Conservative Conventional		0.63	0.63	0.64	0.66	0.67
Moderate Infill Drilling		0.62	0.63	0.64	0.64	0.63
Aggressive Infill Drilling		0.61	0.62	0.63	0.63	0.62
Conservative Offshore Gulf Coast		0.63	0.64	0.65	0.66	0.66
Aggressive Offshore Gulf Coast		0.62	0.63	0.64	0.64	0.62
Conservative Coalbed Methane		0.62	0.63	0.64	0.65	0.63
Aggressive Coalbed Methane		0.62	0.63	0.64	0.64	0.63
Conservative Rocky Mountain		0.62	0.63	0.64	0.65	0.63
Aggressive Rocky Mountain		0.62	0.63	0.64	0.65	0.64
Tight Gas		0.62	0.63	0.64	0.64	0.62
Aggressive North American Conventional		0.62	0.64	0.66	0.66	0.65
Aggressive Canadian Conventional		0.64	0.66	0.69	0.70	0.71
No Canadian Frontier		0.61	0.61	0.62	0.61	0.53
Aggressive Canadian Frontier		0.63	0.63	0.65	0.65	0.64

SOURCE: Canadian Energy Research Institute.

TABLE B.27

CANADIAN NATURAL GAS EXPORTS/
TO MID-ATLANTIC
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	0.08	0.18	0.18	0.18	0.18	0.17
No New Pipelines		0.15	0.15	0.14	0.11	0.07
No PGT Loop		0.18	0.18	0.19	0.19	0.18
No New California		0.18	0.18	0.19	0.19	0.18
No Champlain/Iroquois		0.18	0.18	0.18	0.18	0.17
Conservative Conventional		0.18	0.18	0.19	0.19	0.18
Moderate Infill Drilling		0.18	0.18	0.18	0.18	0.17
Aggressive Infill Drilling		0.17	0.17	0.18	0.17	0.16
Conservative Offshore Gulf Coast		0.18	0.18	0.19	0.19	0.19
Aggressive Offshore Gulf Coast		0.18	0.18	0.18	0.18	0.16
Conservative Coalbed Methane		0.18	0.18	0.18	0.18	0.17
Aggressive Coalbed Methane		0.18	0.18	0.18	0.18	0.17
Conservative Rocky Mountain		0.18	0.18	0.18	0.18	0.17
Aggressive Rocky Mountain		0.18	0.18	0.18	0.18	0.17
Tight Gas		0.18	0.18	0.18	0.18	0.17
Aggressive North American Conventional		0.18	0.18	0.19	0.19	0.19
Aggressive Canadian Conventional		0.19	0.20	0.21	0.21	0.21
No Canadian Frontier		0.17	0.16	0.17	0.16	0.13
Aggressive Canadian Frontier		0.18	0.18	0.19	0.18	0.18

SOURCE: Canadian Energy Research Institute.

TABLE B.28

CANADIAN NATURAL GAS EXPORTS/ TO NEW ENGLAND
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	0.00	0.03	0.04	0.06	0.07	0.07
No New Pipelines		0.00	0.00	0.00	0.00	0.00
No PGT Loop		0.03	0.05	0.07	0.08	0.08
No New California		0.03	0.05	0.07	0.08	0.08
No Champlain/Iroquois		0.02	0.03	0.04	0.05	0.05
Conservative Conventional		0.05	0.06	0.09	0.11	0.12
Moderate Infill Drilling		0.03	0.04	0.06	0.07	0.06
Aggressive Infill Drilling		0.02	0.03	0.04	0.04	0.04
Conservative Offshore Gulf Coast		0.04	0.06	0.08	0.09	0.11
Aggressive Offshore Gulf Coast		0.03	0.04	0.05	0.06	0.05
Conservative Coalbed Methane		0.03	0.04	0.06	0.07	0.07
Aggressive Coalbed Methane		0.03	0.04	0.06	0.06	0.06
Conservative Rocky Mountain		0.03	0.04	0.06	0.06	0.06
Aggressive Rocky Mountain		0.03	0.04	0.06	0.07	0.07
Tight Gas		0.03	0.04	0.06	0.07	0.06
Aggressive North American Conventional		0.03	0.05	0.08	0.08	0.08
Aggressive Canadian Conventional		0.03	0.09	0.17	0.22	0.28
No Canadian Frontier		0.02	0.02	0.03	0.03	0.03
Aggressive Canadian Frontier		0.03	0.05	0.07	0.07	0.07

SOURCE: Canadian Energy Research Institute.

TABLE B.29

CALIFORNIA NATURAL GAS DEMAND
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	2.05	2.36	2.44	2.57	2.65	2.67
No New Pipelines		2.30	2.30	2.37	2.40	2.39
No PGT Loop		2.33	2.41	2.53	2.62	2.64
No New California		2.33	2.40	2.53	2.61	2.64
No Champlain/Iroquois		2.36	2.44	2.57	2.66	2.67
Conservative Conventional		2.33	2.38	2.48	2.54	2.54
Moderate Infill Drilling		2.38	2.48	2.63	2.72	2.75
Aggressive Infill Drilling		2.42	2.55	2.73	2.85	2.88
Conservative Offshore Gulf Coast		2.35	2.42	2.55	2.62	2.63
Aggressive Offshore Gulf Coast		2.37	2.45	2.60	2.69	2.71
Conservative Coalbed Methane		2.37	2.45	2.59	2.69	2.72
Aggressive Coalbed Methane		2.37	2.45	2.60	2.70	2.73
Conservative Rocky Mountain		2.35	2.43	2.56	2.64	2.65
Aggressive Rocky Mountain		2.36	2.45	2.58	2.67	2.69
Tight Gas		2.37	2.46	2.60	2.69	2.71
Aggressive North American Conventional		2.41	2.55	2.73	2.87	2.93
Aggressive Canadian Conventional		2.37	2.46	2.60	2.70	2.72
No Canadian Frontier		2.35	2.43	2.56	2.64	2.64
Aggressive Canadian Frontier		2.36	2.44	2.58	2.66	2.68

SOURCE: Canadian Energy Research Institute.

TABLE B.30

PACIFIC NORTHWEST NATURAL GAS DEMAND
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	0.23	0.31	0.29	0.27	0.30	0.34
No New Pipelines		0.30	0.28	0.25	0.27	0.30
No PGT Loop		0.31	0.30	0.27	0.30	0.34
No New California		0.31	0.30	0.27	0.30	0.34
No Champlain/Iroquois		0.31	0.29	0.27	0.30	0.34
Conservative Conventional		0.30	0.29	0.26	0.29	0.32
Moderate Infill Drilling		0.31	0.30	0.28	0.30	0.34
Aggressive Infill Drilling		0.31	0.30	0.28	0.31	0.35
Conservative Offshore Gulf Coast		0.30	0.29	0.27	0.30	0.33
Aggressive Offshore Gulf Coast		0.31	0.30	0.28	0.30	0.34
Conservative Coalbed Methane		0.31	0.29	0.27	0.30	0.34
Aggressive Coalbed Methane		0.31	0.30	0.27	0.30	0.34
Conservative Rocky Mountain		0.30	0.29	0.27	0.29	0.33
Aggressive Rocky Mountain		0.31	0.29	0.27	0.30	0.34
Tight Gas		0.31	0.30	0.27	0.30	0.34
Aggressive North American Conventional		0.32	0.32	0.30	0.34	0.40
Aggressive Canadian Conventional		0.31	0.31	0.30	0.34	0.39
No Canadian Frontier		0.30	0.29	0.26	0.29	0.32
Aggressive Canadian Frontier		0.31	0.29	0.27	0.30	0.34

SOURCE: Canadian Energy Research Institute.

TABLE B.31

WEST NORTH CENTRAL AND MOUNTAIN NATURAL GAS DEMAND
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	1.90	1.93	1.78	1.76	1.78	1.77
No New Pipelines		1.92	1.77	1.74	1.76	1.75
No PGT Loop		1.93	1.78	1.76	1.78	1.77
No New California		1.93	1.78	1.76	1.77	1.77
No Champlain/Iroquois		1.93	1.79	1.76	1.78	1.77
Conservative Conventional		1.91	1.75	1.71	1.71	1.70
Moderate Infill Drilling		1.94	1.80	1.78	1.80	1.80
Aggressive Infill Drilling		1.96	1.83	1.82	1.85	1.86
Conservative Offshore Gulf Coast		1.92	1.76	1.73	1.75	1.73
Aggressive Offshore Gulf Coast		1.94	1.79	1.77	1.80	1.81
Conservative Coalbed Methane		1.93	1.78	1.77	1.79	1.80
Aggressive Coalbed Methane		1.94	1.79	1.77	1.80	1.80
Conservative Rocky Mountain		1.92	1.77	1.74	1.76	1.75
Aggressive Rocky Mountain		1.93	1.78	1.76	1.78	1.78
Tight Gas		1.94	1.79	1.77	1.80	1.80
Aggressive North American Conventional		1.96	1.84	1.85	1.90	1.94
Aggressive Canadian Conventional		1.93	1.79	1.76	1.79	1.79
No Canadian Frontier		1.93	1.77	1.75	1.77	1.76
Aggressive Canadian Frontier		1.93	1.78	1.76	1.78	1.77

SOURCE: Canadian Energy Research Institute.

TABLE B.32

EAST NORTH CENTRAL NATURAL GAS DEMAND
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	2.98	3.01	2.70	2.62	2.63	2.64
No New Pipelines		3.00	2.68	2.60	2.60	2.61
No PGT Loop		3.01	2.70	2.62	2.63	2.64
No New California		3.01	2.70	2.62	2.63	2.64
No Champlain/Iroquois		3.01	2.70	2.62	2.63	2.64
Conservative Conventional		2.99	2.65	2.55	2.53	2.51
Moderate Infill Drilling		3.03	2.72	2.65	2.67	2.69
Aggressive Infill Drilling		3.05	2.76	2.71	2.74	2.77
Conservative Offshore Gulf Coast		3.00	2.67	2.58	2.57	2.55
Aggressive Offshore Gulf Coast		3.02	2.71	2.65	2.68	2.71
Conservative Coalbed Methane		3.02	2.71	2.63	2.65	2.67
Aggressive Coalbed Methane		3.02	2.71	2.64	2.66	2.67
Conservative Rocky Mountain		3.01	2.69	2.61	2.62	2.63
Aggressive Rocky Mountain		3.02	2.70	2.63	2.64	2.65
Tight Gas		3.03	2.72	2.65	2.67	2.70
Aggressive North American Conventional		3.07	2.79	2.76	2.82	2.89
Aggressive Canadian Conventional		3.02	2.71	2.63	2.65	2.66
No Canadian Frontier		3.01	2.69	2.61	2.62	2.63
Aggressive Canadian Frontier		3.01	2.70	2.62	2.63	2.65

SOURCE: Canadian Energy Research Institute.

TABLE B.33

MID-ATLANTIC NATURAL GAS DEMAND
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	1.65	1.93	1.86	1.85	1.90	1.95
No New Pipelines		1.92	1.84	1.83	1.87	1.90
No PGT Loop		1.93	1.86	1.86	1.90	1.95
No New California		1.93	1.86	1.85	1.90	1.95
No Champlain/Iroquois		1.93	1.86	1.85	1.90	1.95
Conservative Conventional		1.89	1.80	1.77	1.79	1.79
Moderate Infill Drilling		1.94	1.88	1.89	1.95	2.00
Aggressive Infill Drilling		1.98	1.94	1.96	2.03	2.10
Conservative Offshore Gulf Coast		1.91	1.82	1.81	1.84	1.85
Aggressive Offshore Gulf Coast		1.94	1.88	1.89	1.96	2.03
Conservative Coalbed Methane		1.94	1.87	1.87	1.92	1.97
Aggressive Coalbed Methane		1.94	1.87	1.88	1.93	1.99
Conservative Rocky Mountain		1.93	1.85	1.85	1.89	1.93
Aggressive Rocky Mountain		1.93	1.86	1.86	1.91	1.96
Tight Gas		1.94	1.87	1.88	1.94	2.00
Aggressive North American Conventional		1.99	1.96	2.01	2.12	2.23
Aggressive Canadian Conventional		1.94	1.87	1.87	1.92	1.97
No Canadian Frontier		1.93	1.85	1.85	1.89	1.93
Aggressive Canadian Frontier		1.93	1.86	1.86	1.90	1.95

SOURCE: Canadian Energy Research Institute.

TABLE B.34

NEW ENGLAND NATURAL GAS DEMAND
(Tcf/yr)

Case	1987	1992	1997	2002	2007	2012
Reference Case	0.39	0.47	0.46	0.47	0.49	0.51
No New Pipelines		0.46	0.46	0.47	0.49	0.50
No PGT Loop		0.47	0.46	0.47	0.49	0.51
No New California		0.47	0.46	0.47	0.49	0.52
No Champlain/Iroquois		0.47	0.46	0.47	0.49	0.52
Conservative Conventional		0.46	0.44	0.45	0.46	0.48
Moderate Infill Drilling		0.47	0.46	0.48	0.51	0.53
Aggressive Infill Drilling		0.48	0.48	0.50	0.53	0.56
Conservative Offshore Gulf Coast		0.46	0.45	0.46	0.48	0.49
Aggressive Offshore Gulf Coast		0.47	0.46	0.48	0.51	0.54
Conservative Coalbed Methane		0.47	0.46	0.47	0.50	0.52
Aggressive Coalbed Methane		0.47	0.46	0.48	0.50	0.53
Conservative Rocky Mountain		0.47	0.47	0.47	0.49	0.51
Aggressive Rocky Mountain		0.47	0.46	0.47	0.50	0.52
Tight Gas		0.47	0.46	0.48	0.50	0.53
Aggressive North American Conventional		0.48	0.49	0.52	0.56	0.60
Aggressive Canadian Conventional		0.47	0.46	0.48	0.52	0.56
No Canadian Frontier		0.47	0.46	0.47	0.49	0.51
Aggressive Canadian Frontier		0.47	0.46	0.47	0.49	0.52

SOURCE: Canadian Energy Research Institute.

APPENDIX C

THE NORTH AMERICAN REGIONAL GAS MODEL

Appendix C

THE NORTH AMERICAN REGIONAL GAS MODEL

The North American Regional Gas (NARG) Model is an application of the Generalized Equilibrium Modelling System (GEMS), a software package developed by Decision Focus Inc. (DFI). GEMS itself consists of three principal elements:[1]

- a library of process models consisting of a set of mathematical relations that describe physical, behavioural and financial interactions of agents within an economy;
- a network describing the interaction among the different processes; and
- a solution algorithm for determining the numerical values of all variables in the model.

In the NARG model, process models are used to describe production, transmission and consumption activities within the North American natural gas market. The network which links the process models in the NARG model represents the spatial relationship between the various demand and supply regions embodied in the transportation processes which interconnect them. The algorithm used to solve the model finds a set of prices and quantities that, through time, simultaneously satisfy all physical, behavioural and financial relations embodied in the processes and linkages defined by the network. For the NARG specifically, the solution results in a number of market equilibrium prices (market clearing prices) and quantities of natural gas for a particular location at a given point in time over the time horizon of the model.

C.1 Model Structure

The following discussion has been taken largely from model documentation provided by DFI.[2] The NARG model distinguishes four major regional subdivisions including Canada, the United States, Alaska and Mexico. Alaska is represented distinctly from the Lower-48 states because of its remoteness from gas markets. Within each of the major regional divisions of North America there exists subregional detail which, while not disaggregated to the level of individual states or provinces, has been designed in consideration of where the significant demand centres are, where the various supply regions are, and what existing and prospective future pipelines connect each.

C.1.1 Demand Side Structure

For the United States, the degree of regional disaggregation on the demand side is governed by the census regions of the United States. These include the Pacific, Mountain, West North Central, West South Central, East North Central, East South Central, New England, Middle Atlantic and South Atlantic. There is much historical precedent to disaggregating demand regions by census region, and there is much accepted data. Furthermore, climatic distinctions among census regions are usually deemed adequate to reflect different weather and usage patterns throughout the United States.

Some of the census regions have been aggregated in the past because of commonalities amongst them. Transportation differences and climatic differences between certain of the census regions were deemed to be less important than other distinctions made within the model. The CEC NARG model aggregated the New England region and the Mid-Atlantic region of the United States into a single aggregate region largely because the pipeline alternatives were common, there is little indigenous supply, and climatic differences are minor (relatively speaking). This aggregation has been discontinued in the version of the model used in this study to reflect the fact that, with the pipeline proposals pending at this time, the pipeline alternatives may no longer be common in these two regions. Thus, the New England and Mid-Atlantic regions are now modelled as distinct demand nodes in the model. The West North Central region and the Mountain region remain aggregated, largely because the two regions are relatively sparsely populated and little is lost by such aggregation.

The Pacific census region has been disaggregated substantially because of the particular needs of the California Energy Commission. In particular, California has been distinguished from the rest of the Pacific census region. The rest of the Pacific region is termed the Pacific Northwest region. The California demand region is disaggregated into Northern California and Southern California. The specific gas utility service regions within Southern California--Southern California Gas, San Diego and Electric, and Enhanced Oil Recovery--are further distinguished.

To summarize, the model now contains the following thirteen (13) demand regions for the United States:

- Mid-Atlantic
- New England
- South Atlantic

- East South Central
- West South Central
- West North Central/Mountain (aggregate)
- Pacific Northwest
- Northern California (PG&E)
- Southern California Gas
- San Diego Gas and Electric
- California Enhanced Oil Recovery
- Alaska

Turning to Canada, the model aggregates the ten provinces and two territories into four aggregate demand regions. Western Canada includes all provinces west of and including Manitoba, except British Columbia. Eastern Canada includes all provinces east of the Ontario/Manitoba border and is divided into two subregions--Ontario and the rest of Eastern Canada. Ontario is distinguished because of the high concentration of population and industry in the province and because of the economic and political power Ontario wields in Canada. To summarize, Canada is subdivided into four demand regions as follows:

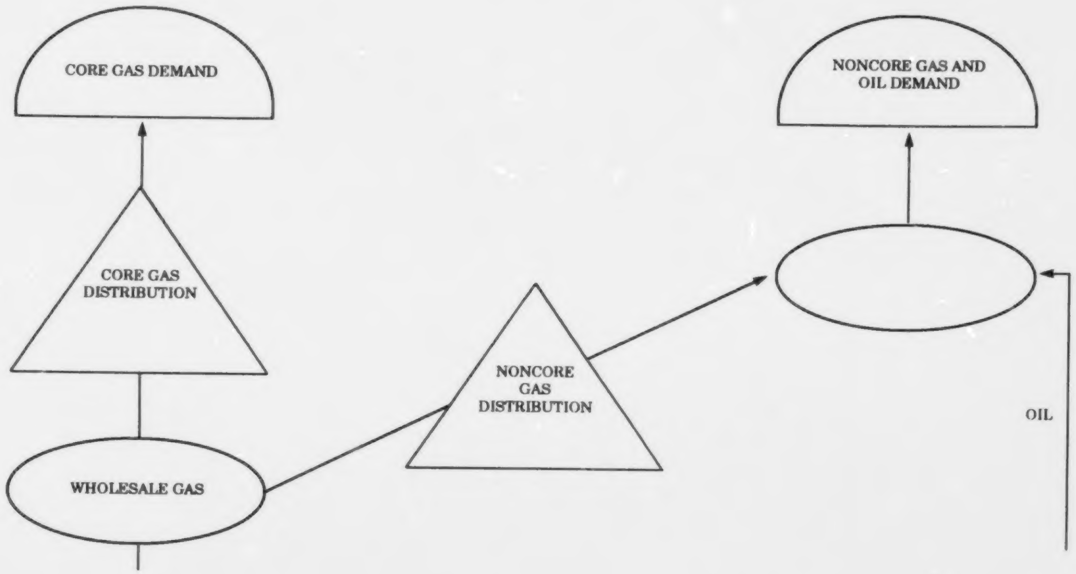
- British Columbia
- Western Canada
- Ontario
- Eastern Canada excluding Ontario.

Inside each of the seventeen demand regions, the model is structured to take account of key demand-side phenomena including demand stimulation at lower prices, demand suppression at higher prices and interfuel substitution between oil and gas. In order to represent such phenomena, it is necessary to recognize the segmented nature of gas demand.

To properly characterize gas demand, it is important to distinguish at least two types of consumers in gas markets. The first, sometimes termed the "core market," is largely captive and exhibits relatively inelastic gas demand. The remainder, termed the "noncore market," is possessed of an immediate alternative such as fuel oil. As long as the gas price remains below that of the alternative, noncore gas demand is relatively firm. If the gas price rises to or above the price of the alternative, noncore gas demand will switch away from gas toward the alternative.

This simple characterization of gas demand can be represented in network form as shown in Figure C.1. In the figure, energy is assumed to flow along the links through the processes from bottom to top. The figure depicts two demand "tombstones," one for core demand and one for noncore demand. Each tombstone contains a demand curve, i.e., a price-quantity relationship that specifies the quantity of gas (or gas-equivalent) that will be

Figure C.1
Network Representation of Core and Noncore Gas Demand


CORE GAS DEMAND
CORE GAS DISTRIBUTION
WHOLESALE GAS
NONCORE GAS DISTRIBUTION
NONCORE GAS AND OIL DEMAND
OIL

SOURCE: Decision Focus Inc.

consumed at every possible price. Notice in the diagram that noncore demand can be satisfied either by gas or by the substitute (assumed to be oil in the diagram). Core demand can be satisfied only by gas.

Economists characterize the simple core/noncore network representation of demand using a demand curve such as that in Figure C.2. The figure delineates the size of the core and noncore markets and shows the assumed oil price. In the figure, gas demand is shown to be equal to core demand for gas prices above the oil price and to be equal to core plus noncore demand for gas prices at or below the oil price.

In reality, core gas demand is somewhat elastic, and noncore gas demand is highly segmented, each segment facing a slightly different substitute price. Therefore, in reality, the demand graph in Figure C.2 should be "rounded off" as shown in Figure C.3. The demand curve in Figure C.3, very characteristic of gas demand, has an inelastic portion at high gas prices, a very elastic "shoulder" for gas prices in the vicinity of the oil price, and an inelastic portion at low gas prices. Results generated by the NARG model rely heavily on the distinctive pattern of gas demand in Figure C.3.

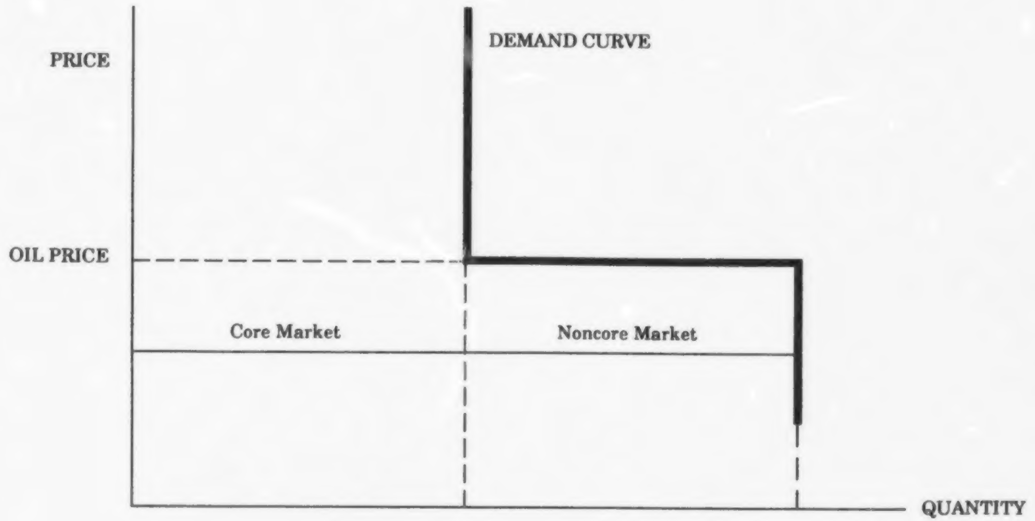
It is interesting to note that the width of the shoulder in Figure C.3 has diminished during the past two decades as the industrial sector of the United States has emigrated or shrunk. What used to be a relatively broad shoulder in a formerly industrialized economy has now become a much narrower shoulder in a service-oriented economy. Such narrowing has vital consequences for the relationship between the market-clearing price of gas relative to the price of oil, implying a much weaker degree of coupling between the two than was true historically.

Every demand region in the model contains the network structure in Figure C.1 and therefore the demand curve structure in Figure C.3. Thus, every demand region in the model represents demand stimulation/repression at different prices as well as substitution at the exogenously given price of the substitute.

The data needed for the demand side of the North American Regional Gas Supply-Demand model is the demand curve in Figure C.3 itself. In order to construct the demand curve in Figure C.3 we need its constituent elements:

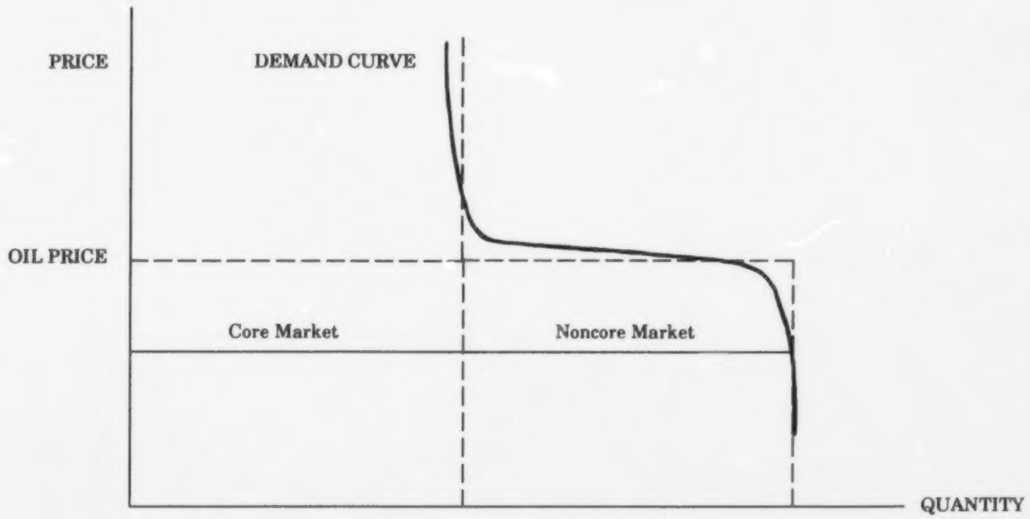
- a demand curve (price versus quantity versus time) for noncore use,
- a demand curve (price versus quantity versus time) for core use,

Figure C.2
Equivalent Representation
Using Demand Curve



SOURCE: Decision Focus Inc.

Figure C.3
Gas Demand Curve



SOURCE: Decision Focus Inc.

- an estimate of noncore distribution cost, which is important in order to properly represent burner-tip gas prices relative to oil prices,
- a projected time schedule of the price of oil against which gas must compete, and
- lag parameters that simulate adjustments in capital stock necessary for gas/oil substitution.

The two demand curves within the demand tombstones for each demand region are inferred from GRI's 1988 Baseline forecast, which is revised annually. In particular, GRI's sectoral gas demand projections are divided into a core (non-substitutable) and a noncore (substitutable) component. A price is associated with each. The quantity demanded together with the associated price constitute a single point on the gas demand curves. A short-run and a long-run demand elasticity are then assumed to characterize how the demand curve varies in the vicinity of the reference quantity and price.

C.1.2 Regional Structure of Supply

C.1.2.1 Regional Structure of the United States

It is not particularly useful to subdivide the supply regions in the model according to political or demographic boundaries (for example, states, provinces or census regions). Rather, it is appropriate to subdivide the supply regions according to existing and prospective natural gas producing potential, that is, to subdivide on a geological basis. In making such subdivision, consideration must be given to the structure of the existing and prospective future pipeline system. In particular, supply regions must be associated with the upstream ends of existing pipelines and with the upstream ends of anticipated new pipelines.

The supply regions in the NARG model were selected with several considerations in mind. First, when it is necessary to distinguish differences among gas producing basins in terms of transportation costs to demand regions that compete for that gas, those basins have been associated with distinct supply regions.

Second, for those sources that will require new pipeline capacity, regional supply distinctions have been made. If a particular resource producing basin relies on the addition of new pipeline capacity to become economically viable, that supply region is distinguished from other supply regions. Indeed, in such cases, the supply region and the outward bound pipelines are inextricably linked, and must be modelled in effect as a pair.

Third, when it is necessary to distinguish resource endowment and cost differences among producing basins, those basins are distinguished by region. In general, there are substantial differences among resource producing regions with regard to extent, cost and distribution of the natural gas resource base. Some would argue that such heterogeneity of the resource base motivates an extremely detailed representation of natural gas supply. Countering such an argument is the observation that much supply-side aggregation is dictated by the specific structure of the pipeline system. Builders of the NARG Model have sought to balance the desire for more supply-side regional and technological detail with the desire to realistically represent the transportation corridors for delivering gas to market.

Fourth, many supply or pipeline projects have direct effects only in localized regions of the United States or Canada, yet the indirect effects proliferate broadly throughout all supply and demand regions of all countries represented. In effect, prices carry economic signals from the single, directly affected region to all other regions of the country along all the paths of the pipeline network. The representation of the pipeline network contains sufficient detail to represent all important existing and prospective future paths.

Fifth, government policy can be region-specific. Excessive aggregation across regions would obviate the ability of the model to properly represent government policy. For example, there are significant tax, financial, and other differences among regions necessitating regional distinctions in the model. A specific illustration is the border price regulations that were imposed by the Canadian government until recently, dictating a common border price at all United States export locations. To model such a policy, one requires substantial geographic detail. The model contains sufficient detail to represent a wide range of such phenomena.

With regard to the conventional and deep natural gas resource base, the Potential Gas Committee (PGC) regions and designations were adopted for three primary reasons. First, much thought has been given to the appropriate degree of regional disaggregation of the conventional resource base by the PGC. No reason was seen to second guess the PGC's efforts. Second, the GRI Hydrocarbon Model has a more aggregated but quite similar regional structure to the PGC regions. Indeed, aggregates of the PGC regions correspond rather closely to the GRI Hydrocarbon Model supply regions. By selecting the PGC regions for the conventional gas resource base, it is possible to access not only the PGC resource base estimates but also the GRI Hydrocarbon Model estimates.

The focus of the Potential Gas Committee (PGC), GRI Hydrocarbon, United States Geological Survey (USGS), Department of Energy (DOE), and other resource base efforts is only upon conventional natural gas. Unconventional gas (tight sands, methane from coal deposits and devonian shale) is associated in the model with conventional gas supply regions and is distributed among the conventional gas supply regions as dictated by their actual physical location. In short, the unconventional gas resource base is distinguished in the same degree of regional detail as the conventional gas resource base, but the realities of where it occurs are properly represented. Using the same regional distinctions for unconventional as well as conventional gas is particularly convenient and thought to be proper because the unconventional gas resource must enjoy the same access to the transportation system as conventional. Coal gasification is regionalized according to coal producing regions of the United States. The major coal producing regions of the United States have been associated with various PGC supply regions and have been placed into the corresponding aggregate NARG model gas supply regions. For example, the North Dakota coal region (where mine-mouth coal gasification might occur) is considered to lie within the Northern Great Plains supply region. Small, exotic sources such as methane from waste or biogas are positioned within the various demand regions, representing the fact that they use only the distribution system, not the transportation system.

The North American Regional Gas model contains a detailed representation of the existing and potential future supply options within each of these regions.

C.1.2.2 Regional Structure of Canada

The regional structure of the Canadian gas system in the NARG and the supporting resource data are taken directly from the structure developed by the University of Saskatchewan and the Canadian Energy Research Institute (CERI) as characterized in CERI Study No. 26,[3] and Rinholm (1987).[4] The Canadian natural gas resource base is distinguished as follows:

- British Columbia
- Alberta
- Saskatchewan
- Eastern Canada
- Mackenzie Delta
- Canadian Arctic (Beaufort Sea, Arctic Islands)

As with the United States, the particular regional disaggregation for Canada was chosen with several purposes in mind. First, it was necessary to survey and represent the location of the primary gas deposits in Canada. It is known that the vast majority of economic Canadian gas occurs within Alberta. Yet, it is also known that there are significant deposits in British Columbia and Saskatchewan and that the latter deposits are positioned differently with regard to the Canadian transportation system.

Second, the Canadian resource base must be distinguished at a level of geographic detail necessary to support analysis of six prospective Canadian border import locations to the United States. This includes the new link into New England. That is, the level of border import and demand detail within the United States dictates the level of resource base disaggregation needed for Canada.

Third, it was necessary to distinguish key demand patterns in Canada, which in the past have influenced not only delivered gas prices in Canada but also export pricing policy. In particular, much of Canadian gas demand occurs within Ontario, which is Canada's most populous and most politically influential province. However, Ontario demand must be served through long distance pipeline from Alberta either indirectly through the Great Lakes system or directly through the TransCanada pipeline. Alberta and points intermediate (i.e., Saskatchewan) must therefore be distinguished.

Fourth, it is necessary to distinguish the more Northern Arctic gas resource base in sufficient detail; otherwise, one cannot predict what is the most economical resource base exploitation pattern and what will be its impact on gas prices throughout North America. In particular, the supply structure representing Canada must be sufficiently detailed to analyze whether the "explore successively up the Mackenzie" strategy is more economical than the "build a pipeline from the North Slope" strategy. The geographic structure contains sufficient level of detail to answer such questions.

Within each of the six Canadian supply regions, the economics of conventional and unconventional gas production at various depth intervals have been represented. Canadian resource cost and geological data were provided to DFI by the National Energy Board of Canada. As noted in the text, CERI has adjusted the geological data somewhat.

C.1.2.3 Nature of the Supply Data

The most elemental economic measure of the cost and extent of the gas resource base is the so-called "resource marginal cost curve" or "resource supply curve," which plots marginal cost against cumulative future additions to proved reserves. The concept and use of a resource marginal cost is discussed in detail in Haas, Nesbitt, and Singh (1987),[5] and rather extensive references to the economics literature are given. Rather than repeating that discussion a simple static supply curve or static marginal cost curve is used to illustrate. No generality will be lost by this simplification; however, it is emphasized that the NARG model employs a very general inter-temporal model of depletable resource production based on a general resource marginal cost curve.

The resource supply curve represents how much gas can be produced by producers at every possible price level. It is not a one-dimensional characterization of the resource base, one that merely "adds up" Btus in the ground. Rather, it is a two-dimensional characterization, specifying precisely how much gas could and would be produced at each given wellhead price level.

It is imperative to consider both cost and quantity and to neglect neither. Only by considering both can we quantify such lay notions as "abundance" or "scarcity" of gas supply. An abundant resource case is one in which the cost of producing each given quantity of resource is low, or alternatively that the quantity of resource available at each given price level is high. Conversely, a scarce resource case is one in which the cost of producing each given quantity of resource is high, or alternatively that quantity of resource available at each given price level is low. Scarcity and abundance are represented using resource supply curves. How could such concepts be represented without appealing simultaneously to both the cost and Btu dimensions? Clearly they cannot.

C.1.3 Geographic Representation of Gas Import Alternatives

Border import locations are positioned at various points along the United States-Canadian border and the United States-Mexican border. There are six border import locations from Canada. There are two prospective border import locations from Mexico represented in the model. LNG import locations are positioned along the East, Gulf, and West coasts at various existing and prospective future locations. The geographic structure of the LNG import locations was discussed previously in conjunction with the demand regions.

Footnotes

[1] A technical description of these three elements can be found in R. L. Phillips, A Methodology and Software System for Linking Economic Models (North Holland Publishing Company, 1983).

[2] See An Overview of the Generalized Equilibrium Modeling System (GEMS) (Palo Alta, California: Decision Focus Inc., 1983) and The California Energy Commission North American Regional Gas Supply-Demand Model (Palo Alto, California: Decision Focus Inc., 1989).

[3] Kevin J. Brown, Towards a Continental Natural Gas Market: Historical Perspective and Long-Term Outlook, Study No. 26 (Calgary, Alberta: Canadian Energy Research Institute, August 1989).

[4] R. Rinholm, "The Canadian Natural Gas Industry: Options and Opportunities,"(Master of Science dissertation, University of Saskatchewan, 1987).

[5] S. Haas, D. Nesbitt, and J. Singh, The GRI North American Regional Gas Supply-Demand Model, GRI Report Number 87-0122 (Palo Alto, California: GRI, 1987).

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